UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Puget Sound Energy, Inc.,
Complainant,

v.

All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement,
Respondents.

Docket Nos. EL01-10-000
EL01-10-001

RECOMMENDATIONS AND PROPOSED FINDINGS OF FACT

(Issued September 24, 2001)

TO THE COMMISSION:

Appearances

On behalf of Portland General:
KATHLEEN L. BARRON, ESQ.
CHERYL FOLEY, ESQ.
CLIFFORD M. NAEVE, ESQ.

On behalf of El Paso Merchant Energy, LP:
KATHERINE C. ZEITLIN, ESQ.
KENNETH IRVIN, ESQ.

On behalf of Northern Wasco People's Utility District:
SHELLY RICHARDSON, ESQ.

On behalf of PPL Montana LLC and PPL Energy Plus, LLC:
JESSE A. DILLON, ESQ.

On behalf of Pinnacle West Capital Corporation:
TIMOTHY BOLDEN, ESQ.

On behalf of Cogeneration Coalition of Washington:
DONALD BROOKHYSER, ESQ.

On behalf of TransAlta Energy Marketing (US) Inc., TransAlta Centralia Generating, LLC, Merchant Energy Group of the Americas:
DAVID TEWKSBURY, ESQ.

On behalf of Northern California Agency:
MEG MEISO, ESQ.

On behalf of Truckee Donner PUD:
MARGARET McGOLDRICK, ESQ.

On behalf of the City of Los Angeles Department of Water and Power:
ANDREW B. ART, ESQ.

On behalf of Public Utility District No. 1, of Chelan County, Washington:
JAMES D. VASILE, ESQ.
DAN ADAMSON, ESQ.

On behalf of Portland General Electric Company:
ALVIN ALEXANDERSON, ESQ.
A. W. TURNER, JR., ESQ.
RONALD W. JOHNSON, ESQ.

On behalf of the City of Tacoma, Washington; Part of Seattle, Washington:
PHILIP L. CHABOT, JR., ESQ.

On behalf of PacifiCorp:
RICHARD GLICK, ESQ.

On behalf of the City of Seattle:
WILLIAM H. PATTON, ESQ.
PAUL S. GREEN, ESQ.

On behalf of Idacorp Energy, LP:
LAWRENCE ACKER, ESQ.

On behalf of Idacorp Energy, LP:
JAMES THOMPSON, ESQ.

On behalf of Exelon Corporation; PECO Energy Company, Exelon Generation Company, LLC and Commonwealth Edison Company:
JONATHAN F. CHRISTIAN, ESQ.
KEVIN J. McINTYRE, ESQ.

On behalf of the Attorney General of the State of California:
LILLIAN S. HARRIS, ESQ.
KEVIN J. McKEON, ESQ.
VICKI P. WHITNEY, ESQ.

On behalf of California Public Utilities Commission:
SEAN H. GALLAGHER, ESQ.

On behalf of PPL Montana, LLC and PPL Energy Plus, LLC:
DONALD A. KAPLAN, ESQ.

On behalf of Public Service Company of New Mexico:
KEVIN M. DOWNEY, ESQ.
JOHN T. STOUGH, JR., ESQ.

On behalf of Pinnacle West Capital Corporation and Arizona Public Service Company:
JOHN McGRANE, ESQ.

On behalf of Wah Chang:
JOEL L. GREENE, ESQ.
EDWARD A. FINKLEA, ESQ.

On behalf of BP Energy Company:
MARK R. HASKELL, ESQ.
MARTIN MARZ, ESQ.
CHRISTIE RICHART, ESQ.

On behalf of Sierra Pacific Power Company and Nevada Power Company:
WILLIAM E. PETERSON, ESQ.

On behalf of Columbia Falls Aluminum Company, Alcoa Kaiser Aluminum:
MICHAEL EARLY, ESQ.

On behalf of Public Utilities Commission of Nevada:
MONTINA M. COLE, ESQ.

On behalf of Salt River Project:
JENNIFER TRIBULSKI, ESQ.
MOTINA COLE, ESQ.
SHERRY QUIRK, ESQ.

On behalf of Transmission Agency of Northern California, Modesto Irrigation District, Cities of Redding and Santa Clara, California and the MSR Public Power Agency:
JAMES PEMBROKE, ESQ.
WALLACE L. DUNCAN, ESQ.
LISA S. GAST, ESQ.
MICHAEL POSTAR, ESQ.
SEAN M. NEAL, ESQ.

On behalf of Mirant Americas, Inc.:
DEBRA RAGGIO BOLTON, ESQ.
Mirant Americas, Inc.

On behalf of Powerex Corporation:

PAUL W. FOX, ESQ.
DEANNA E. KING, ESQ.

On behalf of Public Utility District No. 2 of Grant County, Washington:
BONNIE S. BLAIR, ESQ.

On behalf of Public Utility District No. 2 of Grant County, Washington:
RAY FOIANINI, ESQ.

On behalf of Arizona Electric Power Cooperative, Inc.:
DANIEL M. JAFFE, ESQ.
ROBERT D. ROSENBERG, ESQ.

On behalf of Duke Energy:
MARK PERLIS, ESQ.
Dickstein, Shapiro, Morin & Oshinsky

On behalf of The Montana Power Company:
STEVEN K. KRAMER, ESQ.

On behalf of Eugene Water and Electric Board:
TAMARA TOWNSEND, ESQ.
SCOTT SPETTEL, ESQ.
Cable Huston Benedict Haagenson and Lloyd, LLP

On behalf of Enron Power Marketing/Enron Energy Services:
DAN WATKISS, ESQ.

On behalf of Public Utility District No. 1 of Chelan County, Washington:
DANIEL M. ADAMSON, ESQ.

On behalf of Tenaska Washington Partners, L.P.:
NEIL L. LEVY, ESQ.

On behalf of Tenaska Washington Partners, L.P.:
THOMAS M. TIEHEN, ESQ.

On behalf of Edison Mission Energy and Edison Marketing and Trading, Inc.:
JOHN P. MATHIS, ESQ.

On behalf of Sempra Energy Trading Corporation:
JESSICA FRIEDMAN, ESQ.
MARGARET A. MOORE, ESQ.

On behalf of Sempra Energy Trading Corporation:
ALAN Z. YUDKOWSKY, ESQ.

On behalf of Sempra Energy Trading Corporation:
RICHARD I. BEITLER, ESQ.

On behalf of Sacramento Municipal Utility District (SMUD):
GLEN L. ORTMAN, ESQ.
ADRIAN CLAIR, ESQ.

On behalf of Southern California Edison Company:
RICHARD L. ROBERTS, ESQ.

On behalf of Puget Sound Energy:
GARY BACHMAN, ESQ.
CHERYL FEIK RYAN, ESQ.
BRIAN ZIMMETT, ESQ.

On behalf of Puget Sound Energy:
ROBERT E. NEATE, ESQ.
KIMBERLY HARRIS, ESQ.

On behalf of the Attorney General of the State of CA:
LILLIAN S. HARRIS, ESQ.
KEVIN J. McKEON, ESQ.

On behalf of the Attorney General of the State of California:
BILL LOCKYER, ESQ.
VICKIE P. WHITNEY, ESQ.

On behalf of the United States Department of Energy, Bonneville Power Administration:
GERIT HULL, ESQ.

On behalf of the Office of Attorney General for the State of Nevada, Bureau of Consumer Protection
JOHN E. McCAFFREY, ESQ.
Morrison & Hecker, L.L.P.

On behalf of Washington Utilities and Transportation Commission:
ROBERT CEDARBAUM, ESQ.
SALLY JOHNSTON, ESQ.

On behalf of the Washington State Attorney General:
DAVID WALSH, ESQ.
SIMON FISH, ESQ.

On behalf of the Washington State Attorney General:
SIMON FFITCH, ESQ.

On behalf of Avista Energy and Anista Corporation:
GARY BACHMAN, ESQ.
CHERYL FAIK RYAN, ESQ.CHERYL FAIK RYAN, ESQ.
BRIAN ZIMMET, ESQ.

On behalf of Public Service Company of Colorado:
FLOYD L. NORTON, ESQ.
Morgan Lewis & Bockius

On behalf of the United States Department of Energy:
LOT COOKE, ESQ.

On behalf of Tractebel Power Inc./Tractebel Energy

Marketing, Inc.:
ANDREW N. CHAU, ESQ.

On behalf of Tractebel Energy Marketing, Inc./Tractebel Power, Inc.:
STEVE N. ISSER, ESQ.
HOWARD H. SHAFFERMAN, ESQ.

On behalf of Southern California Edison Company:
CATHERINE GIOVANNONI, ESQ.

On behalf of Southern California Edison Company:
MICHAEL D. MACKNESS, ESQ.

On behalf of Tucson Electric Power Company:
AMIE COLBY, ESQ.
ANTOINE COBB, ESQ.

On behalf of The Montana Power Company:
CARLA J. URQUHART, ESQ.

On behalf of California Public Utilities Commission:
SEAN H. GALLAHGER, ESQ.
California Public Utilities Commission

On behalf of Coral Power, LLC:
RONALD N. POWELL, ESQ.
RONALD CARROLL, ESQ.
KIMBERLY A. CURRY, ESQ.
JACQUELINE JAVA, ESQ.

On behalf of Constellation Power Source:
DAVID PERLMAN, ESQ.
LISA M. DECKER, ESQ.

On behalf of TransCanada Energy Ltd:
MARK F. SUNDBACK, ESQ.
KEN WISEMAN, ESQ.
JENNIFER NICHOLS, ESQ.

On behalf of Morgan Stanley Capital Group and Merrill Lynch Capital Services:
MICHAEL YAFFEE, ESQ.
PAUL J. PANTANO, JR., ESQ.
DORAN EZICKSON, ESQ.
CATHERINE KRUPKA, ESQ.

On behalf of Powerex Corporation:
PAUL FOX, ESQ.
DEANNA KING, ESQ.

On behalf of Powerex Corporation:
RICHARD TABORS, ESQ.

On behalf of the Federal Energy Regulatory Commission Staff:
JANET K. JONES, ESQ.
CARMEN GASTILO, ESQ.

On behalf of PacificCorp and Pacific Corporation Power Marketing:
GEORGE GALLOWAY, ESQ.

On behalf of the Electric Power Supply Association:
ERIN PERRIGO, ESQ.
JUDY SIMON, ESQ.
LYNN CHURCH, ESQ.

On behalf of the Washington Utilities and Transportation Commission:
ROBERT CEDARBAUM, ESQ.
SALLY JOHNSON, ESQ.

On behalf of City of Burbank, California
John R. Stickman, Esq.

I. Background

By order issued July 25, 2001, the Commission ordered a preliminary evidentiary hearing:

> to facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for the period beginning December 25, 2000 through June 20, 2001. The record should establish the volume of the transactions, the identification of the net sellers and net buyers, the price and terms and conditions of the sales contracts, and the extent of potential refunds. This record would help the Commission determine "the extent to which the dysfunctions in the California markets may have affected decisions in the Pacific Northwest.
>
> *See San Diego Gas & Electric Company,* 96 FERC ¶ 61,120 at 61,520 (2001)("*San Diego Gas*") ("July 25 Order").

The Commission instructed that a prehearing conference be held before August 2, 2001, and parties were to provide the data described above to the presiding judge no later than 15 days after the prehearing conference. Thirty days thereafter, the hearing was to conclude. The Commission ordered that the presiding judge make a recommendation and certify the record and findings of fact seven days later.

A. Preliminary Evidentiary Hearing:

On August 1, 2001 a prehearing conference was held, where a procedural schedule was adopted. An order issued on August 3rd, clarified that all sellers in the Pacific Northwest were to submit the data required by the Commission in the July 25 Order. On August 8, 2001 an order was issued approving groups for the marshaling of the evidence and the hearing. To wit, five groups were created. The Net Purchasers Group ("NPG"), the California parties aligned with this group; the Transaction Finality Group ("TFG"); the Federal Power Marketing Group; the State Entities Group and All others. An order establishing the format for the August 16 data submissions was issued on August 9, 2001, modified on August 13 and August 16. These data submissions were requested pursuant to the July 25 Order's language that the record "should establish the volume of transactions, the identification of the net sellers and net buyers, the price and terms and conditions of the sales contracts." *San Diego Gas, supra* slip op. at 43. In accordance with the July 25 Order, data submissions were filed on August 16, 2001. Oral argument was held on August 20, 2001 where a number of matters were addressed.

B. Discovery:

Discovery responses were limited to three business days, served by e-mail with voluminous submissions served on Staff by CD-Rom or diskette. Depositions were not allowed. Discovery responses were subsequently limited to four days and discovery closed on August 30, 2001.

C. August 16 Data Submissions:

The August 16 data submissions were not distributed to all parties but served solely on the presiding ALJ and Staff.

D. Issues:

By order issued August 23, 2001, the following issues were adopted in this proceeding:[1]

1. What were "spot market bilateral sales" in the Pacific Northwest as defined in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839a(14), during the period beginning December 25, 2000 through June 20, 2001?

2. May unjust and unreasonable prices have been charged for spot market bilateral sales in the Pacific Northwest for the period December 25, 2000 through June 20, 2001?

    a. What was the volume of spot market bilateral sales transactions in the Pacific Northwest for the period December 25, 2000 through June 20, 2001?

    b. What were the price and terms and conditions of the sales contracts for spot

---

[1] It bears noting that the parties could not agree on a joint stipulation of issues and filed at least two proposals with various comments.

market bilateral sales transactions in the Pacific Northwest for the period December 25, 2000 through June 20, 2001?

c. Who were the net sellers and net buyers of electric energy in spot market bilateral sales transactions in the Pacific Northwest for the period December 25, 2000 through June 20, 2001?

d. What is the appropriate methodology for determining a just and reasonable rate for transactions that occurred in the bilateral spot market in the Pacific Northwest during the relevant period?

e. Did sellers of electric energy in spot market bilateral sales in the Pacific Northwest for the period December 25, 2000 through June 20, 2001 charge unjust and unreasonable prices?

f. Did any such seller exercise market power, or violate any conditions or limitations of its market based tariffs or agreements entered into under the Western Systems Power Pool Agreement?

3. Are refunds lawful or appropriate for spot market bilateral sales transactions in the Pacific Northwest for the period December 25, 2000 through June 20, 2001 and what is the extent of any potential refunds?

E. Ripple Claims:

Ripple claims have been defined as sequential claims against a succession of sellers in a chain of purchases that are triggered if the last wholesale purchaser in the chain is entitled to a refund. By order issued August 28, 2001 (Order on Ripple Claims) it was determined that ripple claims are essential to determining the existence, and the extent, of refund liability for spot market purchases in the PNW. However, ripple claims were not entertained in this proceeding, because they are contingent on a finding that refunds are due, and because there is no time to develop a record on these claims. Moreover, potential ripple claimants were allowed to submit offers of proof regarding their claims. In this order, it was determined that all parties reserved their rights, without qualification, to raise ripple refund claims in response to any future determination that such parties are liable for refunds.

F. The hearing:

The hearing lasted three days, with cross-examination waived for numerous witnesses. The TFG filed a motion alleging due process violations because of the abbreviated hearing schedule mandated by the Commission. (TFG Renewed Due Process Objections to the Commission"s Abbreviated Briefing And Hearing Schedule filed September 4, 2001).[2]

G. Briefs/Proposed Findings:

Post hearing briefs were filed on September 17, 2001, by the following: Net Purchasers Group; California Parties; Transaction Finality Group;[3] Bonneville Power Administration; Washington Utilities and Transportation Commission, Oregon Office of Energy, and Oregon Public Utility Commission ("Washington Oregon utilities"); Attorney General of Washington; Puget Sound Energy, Inc.; PPL Montana, LLC and PPL EnergyPlus, LLC; Clark Public Utilities; Williams Energy Marketing and Trading; Atofina Chemicals, Inc., Columbia Falls Aluminum Company and Golden Northwest Aluminum, Inc.; Alcoa Inc.; Public Service Company of New Mexico; The City of Redding, California; Grant County, Benton County, Franklin County and Grays Harbor County PUDS; Eugene Water & Electric Board; Sierra Pacific Power Company and Nevada Power Company; Sacramento Municipal District; Enron Power Marketing, Inc. & Enron Energy Services, Inc.; TransAlta Energy Marketing (U.S.), Inc.; IDACORP Energy, LP; POWEREX Corp; Washington PUDs; Duke Energy Trading and Marketing

---

[2]Potlatch Corporation ("Potlatch") filed a motion to intervene on September 4, 2001, replies were due on September 6, 2001. It stands unopposed and therefore for good cause, it is now granted. Potlatch must accept the record that was developed prior to its late intervention. On September 14, 2001 the City of Burbank, California filed a Motion to Permit Interlocutory Appeal of three separate rulings made in this case of three requests by this party. To wit, Order on Motion To Certify Question; Motion To Strike testimony of witnesses and motion for summary Judgment. The motion to Permit Interlocutory Appeal is denied. City of Burbank failed to show extraordinary circumstances warranting the relief it seeks. See Rule 715, 18 CFR § 385.715. On September 19, 2001, the record was reopened for the limited purpose of accepting for filing data submissions from Pacific Northwest Generating Cooperative ("PNGC") and a letter from Reliant Energy Services, Inc. to clarify that its sales to Idaho Power during year 2000 were not made within the refund period of this case or were not made for delivery in or through the Pacific Northwest.

[3] The parties comprising these groups are listed in Order Approving Groups, issued August 8, 2001.

L.L.C.; Public Service Company of Colorado; Modesto Irrigation District; Non Jurisdictional Municipal Systems; Kaiser Aluminum & Chemical Corporation; Wah Chang and Staff.

Additionally, the following parties submitted findings without briefs: El Paso Merchant Energy, L.P.; Pinnacle West Companies; PacifiCorp; McMinnville Water & Light Commission; Morgan Stanley Group, Inc.; City of Burbank. Salt River Project Agricultural Improvement and Power District submitted a letter joining in the brief of the non-jurisdictional municipal entities.

II. RECOMMENDATIONS

For ease of reading the following format is followed in this document: First, the issues are stated. The parties' contentions follow. Finally, my recommendations are described.

A. Procedural Issues in the Commission's July 25 Order:

On July 24, 2001, Puget Sound filed a Motion to Strike. In this motion, Puget Sound sought to strike the following on the grounds that they were not parties to the proceeding, The City of Seattle's Motion to Intervene Out of Time and Opposition to Puget Sound's Motion to Dismiss; Attorney General of Washington Motion to Intervene and Statement of Opposition to Motion of Puget Sound to Withdraw Its Complaint; Answer of City of Tacoma and Port of Seattle to Motion to Dismiss. Puget Sound also filed an Answer in Opposition to the Motions for Leave to Intervene Out of Time Filed by the City of Seattle and the Attorney General of Washington. On July 26, 2001, City of Tacoma and Port of Seattle filed Motions for Leave to Intervene Out of Time.

The July 25 Order did not address the opposition filed by Puget Sound (City of Seattle and Attorney General of Washington). However, the Commission granted as unopposed the following: Oregon PUC, Washington Commission, City of Seattle, Attorney General of Washington. The interventions of City of Seattle and Attorney General of Washington were opposed.

Puget Sound's motion to strike was not addressed in the July 25 Order. It appears that City of Tacoma and Port of Seattle's answer to Puget Sound's motion to dismiss its complaint preceded their intervention requests.

The July 25 Order did not address Tacoma's and Port of Seattle's motions to intervene.

Recommendation: The oppositions to interventions filed by Puget Sound (City of Seattle and Attorney General of Washington), interventions by Tacoma and Port of Seattle and Puget Sound's Motion to Strike should be addressed by the Commission.

B. ISSUES

1. What were "spot market bilateral sales" in the Pacific Northwest as defined in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839a(14), during the period beginning December 25, 2000 through June 20, 2001?

The Attorney General of Washington argues that the definition of spot markets is not the real issue, but that refunds should be ordered for all transactions that were influenced, and made unreasonably costly by the high price of the market transactions in the California market.

NPG:

Net Purchasers Group ("NPG") asserts that the Pacific Northwest spot market bilateral sales for which refunds should be provided in this proceeding include the following:

1) All hourly, daily, weekly, balance of the month, monthly, quarterly and longer purchase transactions of up to one year, for delivery anytime up to one year from the date of the transaction, entered into during the refund period; and

(2) All purchases made during the refund period under contracts and service schedules of any duration at prices tied to Pacific Northwest daily price indices.

According to NPG, in the July 25 Order, the Commission recognized that "spot market" sales for bilateral transactions in the Pacific Northwest may differ from "spot market" sales in the California ISO and PX spot markets.[4] Commissioner Massey stated: "I believe spot sale[s] in the Pacific Northwest could include sales up to a month's

[4] July 25 Order, 96 FERC at 61,520 n.74.

duration or even longer."[5] The record demonstrates that a sensible and fair result is to recognize that, in the Pacific Northwest, "spot market bilateral sales" include transactions entered into during the refund period on a bilateral basis for terms ranging from next-hour, next day, balance of month, monthly, and quarterly through a term of twelve months.

Defining "spot market bilateral sales" in a technical way based upon textbook definitions, power markets in other regions of the country, or an opinion poll that identifies only a subset of typical Pacific Northwest spot market sales transactions only creates arbitrary and inequitable distinctions among parties, depending upon the nature of the transactions they entered into. Likewise, in order to reach an equitable result for Pacific Northwest consumers, the Commission should also order refunds for all purchases made during the refund period under contracts and service schedules of any duration at prices tied to Pacific Northwest daily price indices. NPG argues that there is broad agreement among Commission staff and the load-serving utilities in the Pacific Northwest, whether or not they are seeking refunds in this proceeding, that spot market sales encompass transactions of up to a year citing the testimony of McCullough, Movish, Spettel, Watters and Tingle-Stewart discussed below.

Robert F. McCullough testified on behalf of Seattle City Light that "[t]he Pacific Northwest treats all purchases and sales of less than one year duration as spot purchases."[6] Philip J. Movish testified on behalf of the City of Tacoma ("Tacoma"), the Port of Seattle (the "Port") and Northern Wasco County People's Utility District ("Northern Wasco") that "all hourly, daily, bi-weekly, balance of month, and longer term purchase transactions that are . . . affected by changes in the market clearing price should be considered in the determination of unjust and unreasonable charges."[7] Scott C. Spettel, employed by the Eugene Water and Electric Board ("EWEB") since 1982 in positions relating to power scheduling, management, and planning, testified that he "regard[s] wholesale power bought and sold for terms ranging from next-hour, next-day, balance of month, monthly, and quarterly through a term of twelve months as being 'spot

---

[5] *Id.* at 61,522-23 (Massey, Commissioner, dissenting in part and concurring in part).

[6] Exh. NPG-1 at 11, lines 2-3.

[7] Exh. NPG-45 at 17-18; Exh. NPG-33 at 18.

market' transactions or contracts."[8]

Stan Watters, Vice President of Trading and Originations for PacifiCorp, testified that "PacifiCorp believes that it would be more appropriate to define the spot market, for purposes of these proceedings, to include all transactions of up to and including one month in duration."[9] Mr. Watters explains that PacifiCorp enters into spot transactions of "up to one month in duration that allow [PacifiCorp] to triangulate toward a precise balance of loads and resources."[10] Mr. Watters concludes that:

> We [PacifiCorp] know of no principled basis for distinguishing transactions up to one month in duration that we make from the one-hour purchase or sale that we make on a particular day of the month. Both transactions are integral to the load balancing function of load-serving entities and both are substantially affected by whatever imperfections might have existed in near-term markets.[11]

Commission staff witness Natalie Tingle-Stewart testified that the Pacific Northwest spot markets are not constrained to day-ahead sales. Based on the "terms and conditions" of the transactions identified to Commission Staff by, and the testimony of, many parties in this proceeding, "spot market transactions in the Pacific Northwest should be transactions which are for an hourly, daily, monthly basis and can be up to one year . . . . [T]his appears to be the acceptable business practice of pricing transactions for the entities located within the Pacific Northwest Region."[12]

The Transaction Finality Group ("TFG"), according to NPG, seeks to define the Pacific Northwest spot market as "any transaction with a *duration* of 24 hours or less that

---

[8] Initial Testimony of Scott C. Spettel, Exh. NPG-74 at 7.

[9] Rebuttal Testimony of Stan Watters, Exh. PacifiCorp-1 at 2.

[10] *Id.*

[11] *Id.*

[12] Prepared Direct Testimony of Natalie Y. Tingle-Stewart, Exh. S-1 at 17; FERC Transcript at 1241, lines 10-13.

is *prescheduled* no more than 24 hours in advance of delivery, with an allowance for the conventions of scheduling for weekends and holidays."[13] By their own admission, this definition is not based on information relating to the Pacific Northwest spot market or the "standardized products" sold in that market. Rather, TFG's experts based this definition on "our experience in *other* markets, our experience in *other* regions and so on and so forth that gives a fairly objective definition of what the spot market is."[14] Of course, their "fairly objective" definition rests solely on the TFG's interpretations of generic information drawn from sources unrelated to the Pacific Northwest spot market. For this reason, the "spot market" definition offered by the TFG should be rejected, NPG avers.

For example, NPG argues, the MIT Dictionary of Economics is far too generalized to have any bearing on technical questions specifically relating to the Pacific Northwest.[15] Likewise, the TFG's excerpts from the Chicago Board of Trade's Commodity Training Manual relate to a different geographic region and actually apply only to "cash commodities" such as "actual physical commodit[ies] someone is buying or selling, *e.g.*, soybeans, corn, gold, silver, Treasury bonds, etc." The Bloomberg definition of "spot price" also relates only to a "commodity," which is defined as "food, metal, or another fixed physical substance." None of these definitions relates to the analysis of spot market sales in the Pacific Northwest at issue in this proceeding. According to NPG, TFG's heavy reliance on these unrelated definitions, however, underscores its failure to address the unique features *i.e.*, the realities, of the Pacific Northwest spot market.

The TFG, NPG argues, attempts to rationalize its artificial limitation of "preschedul[ing]" within 24 hours of delivery requirement by focusing on the concept of "immediate delivery."[16] The TFG extracts this concept from definitions found in such sources as the MIT Dictionary of Economics, the Chicago Board of Trade's Commodity Training Manual, and the Bloomberg website.[17] *None* of these sources, however, defines the term "immediate delivery" as delivery within any specific period of time (such as 24

---

[13] Exh. AE-1, at 14 (emphasis added).

[14] Van Vactor, FERC Transcript at 1116 (emphasis added).

[15] See ENR Ex.-28.

[16] *See* Exh. ENR-25, at 4-5.

[17] *See* Exhs. ENR-26, ENR-27, ENR-28, ENR-29.

hours). Recognizing this defect in their claim, the TFG merely offers that "[t]he physical mechanisms for delivery of commodities shape the structure of the relevant spot market, according to NPG."[18]

NPG further argues that nothing in the definitions the TFG cites states that spot market sales must result in product deliveries that have a duration of no more than 24 hours. Transactions for "immediate delivery" may extend in duration well beyond the artificial 24-hour limitation espoused by the TFG. For example, balance-of-the-month electricity transactions are a prevalent form of trading in the Pacific Northwest, as the TFG admits.[19] The TFG further admits, as it must, that these transactions "us[e] much the same process as described for the bilateral day-ahead market (except for the fact that the period being traded is the remainder of the month)."[20] Given the realities of the relevant market, argues NPG, and even reading the generic definitions on their face, the undefined term "immediate delivery" clearly does not support the TFG's 24-hour *durational* restriction on "spot market" sales in the Pacific Northwest.

To compensate for the scant experience of its "experts" in the Pacific Northwest power market,[21] the TFG claims that its "spot market" definition takes into account relevant market practices simply because one of its experts conducted four telephone interviews and an "informal survey" of Pacific Northwest traders.[22] According to NPG, TFG admits, however, that both the telephone interviews and "informal survey" *were all with employees of TFG members*,[23] at least five of whom were actually witnesses for

---

[18] Exh. ENR-25, at 2.

[19] *See* Exh. ENR-25, at 6.

[20] Exh. AE-1, at 13.

[21] *See* Transcript at 1125-27.

[22] *See* Exh. ENR-10, at 9; Exh. ENR-25, at 3.

[23] *See* FERC Transcript at 1144-45.

TFG members.[24] Moreover, of the 26 survey respondents, only two or three represented load serving utilities.[25]

NPG argues that Pacific Northwest spot market sales encompass monthly, quarterly and yearly transactions because all involve “standardized product[s]” traded on the spot at transparent and fluctuating prices. As Tim Culbertson, who testified on behalf of Public Utility District No. 2 of Grant County and three other PUDs, explains:

> I believe the definition ought to focus on how standard the product is, how liquid the product is, and how transparent the price is . . . . I believe that “spot market” should be defined on a longer basis than the real-time and day-ahead transactions due to the fact that monthly, quarterly, and even transactions up to a year involve a standardized product, can be consummated just fast as a day-ahead or real-time deal, and trade at prices that are, for the most part, transparent.[26]

It is appropriate to define the Pacific Northwest spot market in terms of standard products because all standard products are bought and sold on the “spot” at prices that are transparent, NPG maintains. Standard products are typically traded during a brief direct telephone call either involving a broker or person-to-person contact.[27] Such transactions are generally not the product of lengthy negotiations as in the case, for example, of a 20-year power sales agreement. The process by which such standard product transactions are conducted is basically the same for hourly, daily, monthly, quarterly, and yearly transactions, according to NPG.

NPG asserts that the nature of the Pacific Northwest spot market reflects the scheduling difficulties imposed by widespread reliance on hydroelectric resources. The “Northwest Power Pool generation mix is dominated by hydroelectric generation.”[28]

---

[24] *See id.* at 1145-48.

[25] *See id.* at 1148-49.

[26] Prepared Answering Testimony of Tim Culbertson, Exh. GT-1 at 6.

[27] *See, e.g.*, Stelzer, Exh. AE-1 at 13, lines 1-11.

[28] Prepared Direct Testimony of Robert F. McCullough, Exh. NPG-1 at 6. S*ee also*

(continued...)

"[P]rimarily hydroelectric systems operate very differently from thermal systems like those in California."[29] Hydroelectric resources "are fuel limited, not capacity limited . . . . The operating problem that faces Pacific Northwest generators is that the hydroelectric projects do not have enough water to meet all of the loads – even though they might well have sufficient capacity to meet peak loads without any need for any other resources."[30]

Because hydroelectric projects "are not capable of running all of the time," Pacific Northwest load serving utilities must make spot purchases "on an hourly, daily, weekly or monthly basis to 'refill' reservoirs."[31] The fact that the Pacific Northwest relies primarily on hydroelectric resources forces load serving utilities to purchase standard products for periods of a day, week, month, quarter and year that are traded on the spot, NPG argues. As Mr. McCullough testified, the Pacific Northwest spot market is related to "the Pacific Northwest Coordination Agreement which controls how the major [hydroelectric] projects are dispatched. This Agreement envisages that all purchases and thermal dispatch will be block loaded to stretch the available supply of hydroelectricity."[32]

Pacific Northwest load serving utilities, which rely primarily on hydroelectric resources, should not be punished for prudently purchasing power on weekly, monthly, quarterly or yearly bases, NPG avers. These utilities made purchases of these durations

(...continued)
Prepared Responsive Testimony of Christopher Stelzer, AE-1 at 3 ("over 60% of the Pacific Northwest's energy supply will come from hydroelectric facilities in a typical year, and the percentage has been even higher in the past"); Prepared Direct Testimony of Natalie Y. Tingle-Stewart, S-1 at 8 ("hydro power supplies approximately 60 to 70 percent of the electricity in the Northwest"); Prepared Direct Testimony of Dolores Stegeman, NPG Exh. 27 at page 3, lines 76-77.

[29] Prepared Direct Testimony of Robert F. McCullough, Exh. NPG-1 at 5.

[30] *Id.*

[31] *Id*. *See also* Rebuttal Testimony of Stan Watters, PacifiCorp-1 at 3 ("[as we [PacifiCorp] get closer to the month of delivery, we begin a process of buying and selling power in transactions of up to one month in duration that allows us to triangulate toward a precise balance of loads and resources.").

[32] McCullough, Exh. NPG-1, at 11.

in order to balance their expected load and resource needs and requirements.[33] This practice comports with the Commission's stated objective that load serving utilities should not overly rely on the more volatile next-hour and next-day purchases.[34] It also is consistent with good public policy, NPG maintains.

The bilateral transactions for which refunds should be permitted should also include all sales during the refund period under contracts or service schedules of any duration tied to Pacific Northwest daily price indices, according to NPG. NPG avers that those price indices were affected by the distorted market clearing prices in the California PX and ISO spot markets.[35] These transactions would include, for example, all purchases under contracts pursuant to which prices are "market indexed and based on the Dow Jones Mid-Columbia Electricity Price Index."[36] The dysfunction in the California PX and ISO spot markets negatively impacted daily price indices in the Pacific Northwest.[37] Therefore, NPG argues, the prices at which power was bought and sold in the Pacific Northwest during the refund period under contracts and service schedules tied to Pacific Northwest daily price indices were rendered unjust and unreasonable,

---

[33] *See, e.g.*, Rebuttal Testimony of Stan Watters, Exh. PacifiCorp-1 at 3. (PacifiCorp enters into transactions of "up to one month in duration" to achieve "a precise balance of loads and resources"); Green Exh. NPG-4 at 10, lines 225-27 ("SCL's trading activities are limited to purchasing power to meet native customer loads . . . and selling energy during times of surplus"). Direct Testimony of Dolores Stegeman, Exh. NPG-27 at 829, lines 185-196 ("These resources provide a low-cost stable base for Tacoma Power's portfolio.").

[34] *See, e.g.*, June 19 Order, 95 FERC at 62,546 ("reduction of the size of the ISO's spot market . . . was, and remains, the cornerstone of our price mitigation").

[35] *See* Prepared Direct Testimony of Philip J. Movish on Behalf of the City of Tacoma and Port of Seattle, Exh. NPG-33 at 17; Prepared Direct Testimony of Philip J. Movish on Behalf of Northern Wasco, Exh. NPG-45 at 16 (same); Puget Complaint at 8 (noting "a high degree of correlation between" the index of California electricity prices and the Dow Jones Mid-Columbia Electricity Price Index).

[36] Exh. NPG-45, at 17.

[37] *See* Exh. NPG-33, at 17.

regardless of whether the underlying transaction is entered into pursuant to a short- or long-term contract.[38]

Furthermore, NPG avers, refunds for these transactions comport with the Commission's responsibility to protect all purchasers from not only unjust and unreasonable rates, but also discriminatory treatment.

According to NPG, two primary competing proposals of what constitutes the "Pacific Northwest" have emerged in this proceeding: 1) the geographic area encompassed by the Northwest Power Pool ("NWPP"); and 2) the drainage basin of the Columbia River and its tributaries as defined in the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (the "PNEPPCA"), 16 U.S.C. §§ 839a(14). The first proposal defines an appropriate geographic area; the second is inapplicable to this proceeding.

The geographic scope of the NWPP "is an area th[at] includes the utilities that are active in trading electricity within the Pacific Northwest."[39] "It is logical to use the marketing area for the Pacific Northwest [for the purpose of determining the extent of potential refunds in this proceeding], not an arbitrary geographic division of that area."[40] Moreover, NPG avers, the area encompassed by the NWPP "is a definition of very long standing," because the NWPP has been in operation since 1957, and the Pacific Northwest Coordination Agreement, which governs the relationship among Northwest utilities, was signed in 1962.[41]

On the other hand, NPG maintains, the geographic area defined in the PNEPPCA is inappropriate. The PNEPPCA definition encompasses an area significantly smaller than the NWPP, and its boundaries would cut through service areas such as

[38] *See* Movish Rebuttal Testimony, Exh. NPG-60 at 3.

[39] Prepared Direct Testimony of Robert F. McCullough, NPG-1 at 2-3.

[40] *Id.*

[41] *Id. See also* Prepared Answering Testimony of Tim Culbertson, GT-1 at 7-8 (agreeing that definition of "Pacific Northwest" should be based on the Pacific Northwest Coordination Agreement).

PacifiCorp's.[42] This definition "has more to do with the environmental issues in the [PNEPPCA] than anything to do with [the WSCC [Western Systems Coordinating Council] market.]"[43] As all of the area encompassed by the NWPP is included in the WSCC, and the Commission has ordered prospective price mitigation for the WSCC, it is appropriate to use the NWPP area.

The PNEPPCA definition encompasses a narrow geographic band (75 miles) around the Columbia River and its tributaries, intended to include "the anadromous fisheries that have been severely threatened by the hydroelectric projects along the Columbia River. This simply has nothing to do with the WSCC market."[44] The Commission should use a geographic area relevant to electric power marketing, *i.e.*, the area covered by the NWPP, not an irrelevant geographic area related to fish and wildlife management concerns.

California Parties:

California Parties argue along similar lines as the NPG. According to the Calfornia Parties, all experts agreed that the "spot market" in the PNW was not limited to real-time or near real-time transactions, but included some forward transactions and can extend to longer-term transactions influenced by daily index prices. (Movish, NPG-33 at 12-15; Saleba, GSS-1 at 7:4-11; Wolak, CAL-5 at 6:19-9:7; Mason, NPG-62, at 6:25-7:6; Watters, PacifiCorp-1 at 4-5). The only point of disagreement concerns which forward transactions to include. Short-term forward power transactions are designed to "fill in" the availability of hydroelectric projects to meet load. (McCullough, NPG-1 at 6:19- 7:1). These "fill in" transactions form the spot market and these transactions can vary in form and duration. For instance:

•Seattle City Light [seeking refunds] defines the spot market as including transactions up to one year based on conventions established in the PNW Coordination

[42] *See* NPG-1 at 3-4.

[43] Rebuttal Testimony of Robert F. McCullough, NPG-68 at 7.

[44] *Id., see* 16 U.S.C. § 839(6) (1994) (one of several purposes of the PNEPPCA is "to protect, mitigate and enhance the fish and wildlife . . . of the Columbia River and its tributaries, particularly anadromous fish").

Agreement. (McCullough, NPG-1 at 11:2-3.)

•Eugene Water and Electric Board [seeking refunds] regards transactions ranging from next-hour, next day, balance of month, monthly, quarterly and even a term of twelve months to be spot. (Spettel, NPG-74 at 7.)

•City of Tacoma, Port of Seattle and Northern Wasco County Peoples Utility District [seeking refunds] asserted that all hourly, daily, bi-weekly, balance of the month, and longer term purchase transactions indexed at prices that may change on a daily or hourly basis are "spot transactions." (Movish, NPG-33 at 17-18 and Movish Rebuttal, NPG-60 at 18.)

•Public Utility District No. 2 of Grant County [not seeking refunds] states that spot transactions encompass monthly, quarterly, and even transactions up to a year because all involve standardized products traded at transparent and fluctuating prices. (Culbertson, GT-1 at 6-7.)

•Bonneville Power Administration ("BPA") [not seeking refunds], the entity that according to the Transaction Finality Group ("TFG") dominates the marketing of power in the Northwest (Van Vactor, ENR-1 at 1:22-11:2), classifies spot transactions as including all sales within a month and balance of the month. (Oliver Direct, BPA-1 at 5).

•PacifiCorp [not seeking refunds] advanced that it would be proper to define the spot market to include all transactions of up to, and including, one month in duration. (Watters, PacifiCorp-1 at p.2.)[45]

•FERC Staff concluded that spot market transactions in the PNW should consist of transactions which are for an hourly, daily, monthly basis and can be up to one year. (Tingle-Stewart, S-1 at 17.)

---

[45] Mr. Watters on behalf of PacifiCorp concluded that there is "no principled basis for distinguishing transactions up to one month in duration that we make from the one-hour purchase or sale that we make on a particular day or month. Both transactions are integral to the load balancing function of load-serving entities and both are substantially affected by whatever imperfections might have existed in the near term-markets." (PacifiCorp-1 at 4-5.)

Like the NPG, California Parties contend that in the physical commodities markets, upon which the TFG heavily relies,[46] a spot transaction may "initiate" immediate delivery, but it rarely, if ever results in immediate receipt by the purchaser. Equally significant, the immediate delivery in the physical commodities market has no relation to the rate of consumption by the purchaser. Electricity cannot be stored. Therefore, a purchaser of spot electricity cannot accept it all at once and ration it over the time period in which it is needed. Thus, the TFG's definition necessarily rests on a concept of immediacy that is irrelevant to the electricity market

Moreover, as noted by BPA, "[w]ithin the month and balance of the month transactions can be very-short-term in nature (days), and are usually made because of unanticipated changes in load or generation, after the month begins." (Oliver, BPA-1 at 6.) Thus, while the 24-hour time frame may conform to scheduling conventions, and there will be a need for real-time balancing of resources, these facts should not and do not comport with the reality of short-term purchasing decisions in the PNW. If schedulers know that an energy requirement exists, they will normally choose to make one purchase rather than multiple daily transactions, California Parties maintain. (McCullough Rebuttal, NPG-68 at 16.)

Rather than constrain the definition of "spot market" to a narrow range of transactions, the Commission recognized that the definition of spot market must serve "to determine the extent to which the dysfunctions in the California markets may have affected decisions in the Pacific Northwest."[47] Dr. Frank Wolak, witness for the California Parties, explains that market power can influence short-term power purchases because it takes approximately two years for a new entrant to deliver new supply; sellers of electricity for delivery of energy within this two-year time frame can exercise market power and drive prices above the prices that would prevail in a workably competitive market. (CAL-5 at 3:10-6:15.) Because the Commission has the responsibility under the FPA to ensure that electricity is sold at just and reasonable rates, the definition of "spot market" for purposes of this proceeding should include all transactions that could have

---

46 The TFG, for example, cites to the excerpts from the Chicago Board of Trade's Commodity Training Manual and Bloomberg. The Chicago Board of Trade refers to "cash commodities" such as "actual physical commodity[ies] someone is buying or selling, e.g., soybeans, corn, gold, silver, treasury bonds, etc." Similarly, the Bloomberg cite refers to a commodity which is defined as "food, metal, or another fixed physical substance."

47 July 25 Order, 96 FERC at 61,520.

been tainted by the exercise of market power, the California Parties state.

The August 23, 2001, *Order on Issues* adopted the definition of the PNW set forth in the Pacific Northwest Electric Power Planning and Conservation Act ("Conservation Act").[48] For the California Parties, the issue is not how to geographically define the PNW. Rather, the question is what constitutes a sale in the PNW. Industry custom, fundamental notions of justice, as well as prior orders in this proceeding and prior Commission orders, dictate that transactions encompassed by this proceeding should properly include all purchases and sales of electric energy that originate, are delivered to, or are transmitted in the area defined by the Conservation Act or in the broader WSPP area as advocated by NPG.

Refunds for sales to CERS in the PNW are appropriately pursued in this proceeding. Under the July 25 Order, CERS' bilateral contracts in the PNW are eligible for refunds, just as are those of every other purchaser of power in the PNW. While suppliers may argue that this proceeding is intended to address only the claims of entities *physically located* in the PNW, the Commission and orders in this proceeding have previously ruled to the contrary. Regardless of whether the wholesale purchaser or retail end-user resides in California or the PNW, if the power in question was purchased in the PNW under a bilateral contract, it is within the scope of this proceeding. The July 25 Order affirms that, to the extent CERS was a party to transactions in the PNW, those transactions are eligible for refunds, the California Parties argue.

The refund claim of the California Parties in this proceeding consists of the subset of CERS transactions made at or through certain interconnections with control areas in the PNW. (Tr. at 886:23-888:1 and 921:13-16.)[49] BPA -- a party adverse to the California Parties in this proceeding -- acknowledges that the border delivery points known as the California Oregon Border ("COB") and the Nevada Oregon Border ("NOB") are "in the PNW" within the meaning of the statute. (Oliver Direct, BPA-1 at 5). Similarly, according to the California Parties, the TFG admits that the Conservation Act definition "includes all of the region's important electricity trading hubs for the [PNW]; those hubs are the California Oregon boarder ("COB"), Mid Columbia

---

[48] (**See also**) July 25 Order, 96 FERC at 61,502 fn. 19.

[49] (**See also**) Affidavit of William Green filed on August 23, 2001 as Attachment 1 to the Answer of the California Parties to the Motion of the Transaction Finality Group to Strike Testimony of the California Parties.

("Mid-C"), and the Northern Rockies." (Van Vactor, ENR-1 at 5:17-19; Adamson, ENR-10 at 7:2.)

Furthermore, the California Parties argue, each transaction underlying the California Parties' refund claim was entered into pursuant to the Western Systems Power Pool ("WSPP") Agreement. (Tr. at 864:12-14 and 889:8-12.)[50] Section 33.2 of the WSPP Agreement provides, in pertinent part, that "[t]itle to and risk of loss of the electric energy shall pass from the Seller to the Purchaser at the delivery point agreed to in the Confirmation Agreement."[51] Thus, it is an essential indicium of completion of the wholesale transaction, i.e., the transfer of title of the electrical energy, occurred within the PNW.

In furtherance of its argument, the California Parties contend, that nothing in the July 25 Order suggests that refunds for PNW bilateral transactions will be considered for all parties *except* CERS. The July 25 Order excludes CERS' and all other bilateral transactions from the *San Diego* refund proceeding, ruling that that proceeding is confined to transactions through the ISO and CalPX markets.[52] It does not preclude consideration of refunds for *all* bilateral transactions entered into by any California party in *any* market. The Commission did not limit in any manner the identity of purchasers who may be eligible for refunds in the PNW.

While the California Parties have requested rehearing of the Commission's erroneous decision to exclude CERS' transactions from refund consideration in the *San Diego* docket, CERS' bilateral transactions in the PNW are *not* purchases through the California ISO or PX markets. Consequently, refund claims in this proceeding as to such transactions do not duplicate claims currently set for evidentiary hearing in the *San Diego* case.[53] Rather, to the extent that CERS had bilateral purchases in the PNW, such purchases are the functional equivalent of other purchases made in the PNW by a

---

50 The exceptions are exchange agreements outlined in CAL-3.

51 The WSPP Purchase Agreement is S-6, introduced by Staff Witness Poffenberger.

52 96 FERC at 61,515.

53 As Mr. Green testified, *all* of the California Parties' claims for transactions in the PNW are asserted in this proceeding. (CAL-1 at 2:19-23, 4:2-5, 5:5-9; Tr. 877:21-878:8; Tr. 880:9-15.) No other claims are asserted in this proceeding.

Washington municipal utility or a California municipal utility.

In the August 9 "Order On Format For Data Submissions," it was ruled (slip op. at 8-9) that "all transactions which originate, are delivered, or must be transmitted in the PNW must be reported." Necessarily, this includes sales to CERS at PNW delivery points.

In the August 24 "Order On Motion To Strike Testimony," the TFG's motion to exclude CERS transactions was denied stating:

> *that bilateral transactions of the CDWR* in the PNW (as specified in the August 9 order) during the period at issue in this proceeding, *are relevant* to establishing a factual record concerning the volume of transactions, the identification of net sellers and net buyers, the price and terms and conditions of the sales contracts, and the extent of potential refunds, *as mandated by the Commission*.[54]

Finally, this order stated that it was "significant that the Commission in the July 25 Order, did not exclude CDWR from this proceeding," and ruled that "the Commission did not limit in any manner the identity of purchasers who may be eligible for refunds in the PNW."[55]

Thus the California Parties submit that the Commission has precluded recovery of refunds for bilateral purchases in California, but has never precluded recovery of refunds by California purchasers under bilateral contracts in the PNW. A contrary position would create an arbitrary and capricious distinction between purchasers of wholesale electricity in the PNW who are physically located in that geographical region, and those physically located elsewhere. Simply stated, one group cannot receive the protection of just and reasonable rates, while the other does not.

TFG:

The TFG argues, although the series of orders issued in the *San Diego* docket

---

[54] *Id*, slip op. at 6 (emphasis added).

[55] *Id*, slip op. at 7.

consistently define the spot market as the market for transaction of 24 hours or less, the July 25 Order questions whether the definition of spot market for the PNW may be different.[56] The evidence establishes that the appropriate definition of "spot market" in the PNW means one-time contracts for *immediate* delivery of electrical energy. An overwhelming majority of market participants have testified that "only transactions of no longer than 24 hours in length, entered into no more than 24 hours in advance [of delivery] . . . are spot market transactions." Exh. AU-1 at 4:62-64; *see also* Exh. ENR-1 at 8:22-24, 9:1-2; Exhs. ENR-26 through ENR-29.

According to TFG, in the PNW "spot market" means the sale of power for immediate delivery:

- "The definition of 'spot' transaction is typically defined to be transactions for immediate delivery, at prevailing prices." Exh. ENR-10 at 6:7-8; 8:13-16.

- "[A] spot market transaction in the [PNW] region [is] a transaction with a duration of 24 hours or less that is prescheduled no more than 24 hours in advance of delivery." Exh. AE-1 at 14:21-23.

- "[S]pot transactions are the result of a purchaser's need to buy elasticity on an immediate real-time basis. Thus, spot transactions have been for durations of 24 hours or less and have been consummated almost on an immediate basis. . .The only exception that is commonly accepted in the Western Systems Coordinating Council is in relation to the daily spot market. That exception occurs when the consummation of the transaction is intended to happen immediately after a weekend day, holiday, or a WSCC scheduler conference." Exh. IE-1 at 11:19-12:8.

- Spot market transactions are "[t]ransactions entered into with a duration of 24 hours or less . . . In the PNW and [WSCC] region generally, the spot market is limited to 24 hours sales. I am aware of no industry standard that considers transactions

---

56 96 FERC at 61,520 at n.74.

longer than 24 hours to be spot market transactions." Exh. RED-1 at 7:13-20.

- "The spot markets for the bilateral trading of electricity are understood to be the real-time and prescheduled or day-ahead markets." Exh. ENR-1 at 8:22-9:2.

- "The key concept in the definition of spot markets and prices is 'immediacy.'" Exh. ENR-25 at 4:14-14.

- Spot market transactions "are entered the day-of or day-prior to delivery … are 24 hours or less … provide for deliveries in a specific hour or hours up to 24 hours in advance … [and] … [s]pot market contracts almost always go to delivery." Exh. PWX-1 at 24:9-19.

The correctness of this definition, TFG maintains, is evidenced by the multitude of similar industry definitions, as well as the definition used by the Commission and its Staff. As the evidence shows, NYMEX, Bonneville Power Administration, the California ISO, and the Canadian NEB Electricity Trends and Issues all define "spot market" in terms of sales for "immediate delivery." *See* Exh. S-1 at 13:3-15:8; Exh. SMD-1 at 6:3-7:15; Exhs. ENR-26 through ENR-29. The Commission, itself in several orders in the EL00-95 docket, has defined "spot market" as sales that are 24 hours or less, which are entered into the day of or day prior to delivery.[57] Furthermore, the Commission's Staff has previously defined "spot market" for purposes of electricity sales as "[a] market where goods are traded for immediate delivery." Exh. TFG-26; *see also* Tr. at 1222:25-1230:8.

Thus, "immediate delivery" is an important criterion of many spot markets. As noted by Mr. Adamson, electricity is deliverable immediately, unlike other commodities such as coal, which is typically shipped in vast quantities by train, barge or ship. Exh. ENR-25 at 3:

---

[57] *See, e.g.*, June 19 Order at 62,545 n.3 ("As used throughout this document, the terms 'spot markets' or 'spot market sales' means sales that are 24 hours or less and that are entered into the day of or day prior to delivery.").

> Electricity is delivered simultaneously with production, via the high voltage transmission system. For this reason, spot market definitions for electricity are generally defined (such as the Real-Time Market of the California ISO referred to by Ms. Tingle-Stewart at 16) as operating on very short-time horizons. As delivery is instantaneous in electricity, the defining characteristic of electricity spot market transactions is the timing of scheduling of transactions. The underlying scheduling process for delivery in the PNW operates on a daily basis. This supports my fundamental conclusion that a 24-hour or less ahead (with weekend, holiday and WSCC scheduler conference exceptions) definition is the appropriate one for the PNW bilateral spot market in electricity.
>
> Exh. ENR-25 at 3.

Cross-examination of witnesses supporting this view only bolsters this point that TFG asserts. For example, Mr. Adamson testified:

> [M]y judgment about the appropriate definition of the spot market really had two components, an economic one and a practical one…. In terms of the practical one,. . .how I tried to verify my understanding of the market, . . . I conducted a telephone survey with four traders, [and] [t]here's also kind of an e-mail survey that went out. . . . [From that,] it is my conclusion, as I describe in my rebuttal testimony on page 4, that the 24-hour-or-less market meets the correct economic definition of a spot market.

Tr. at 1112:10-1113:3. Likewise, Mr. Van Vactor testified:

> [T]he opinion we're trying to offer [about the definition of spot market] is based on our experience in other markets, our experience in other regions and so on and so forth, [all of which] gives a fairly objective definition of what the spot market is. And it is by and large, across a whole set of markets, a daily market. It is not a year-long [or] month-long market.

Tr. at 1116:9-16. When pressed further about the differing view of the Bonneville Power Administration's ("BPA") witness, Mr. Adamson responded:

> I do not [agree with the definition of spot market transactions used by Stephen Oliver, witness for the BPA]. Mr. Oliver would treat within-the-month and balance-of-month transactions [as] spot transactions, claiming these are not discretionary in nature…. However, this distorts the definition of spot which centers [not] on whether … the transaction is discretionary but rather whether or not [the transaction] is for immediate delivery.
>
> Tr. at 1118:11-25.

In contrast to the testimony that "spot market" concerns sales for immediate delivery, the testimony of the claimants' witnesses was unsupported by any structural justification, trade practice or practical distinction according to TFG. *See, e.g.*, Tr. at 576:4-14 (under definition espoused by City of Seattle, "all of Seattle City Light's transactions between December 25, 2000 and June 19, 2001 are considered spot market … purchase transactions"). Even Ms. Tingle-Stewart, the Staff's witness who advocated an expansive definition of "spot market," stated on cross-examination that "spot market" for purposes of this proceeding cannot, by definition, include all sales transactions. Tr. at 1214:22-1215:22. Ms. Tingle-Stewart further stated that "typically [a] spot market is usually 24 hours or less" and identified no structural distinctions of the PNW markets that would justify a definition different than the "typical" one. Tr. at 1215:20-22.

If the Commission had intended to conduct an inquiry into the prices charged for all transactions in the PNW, it could readily have done so; instead, it limited the inquiry to "spot market" transactions TFG avers. Its guidance should not now be discarded to sweep in nearly all transactions under the rubric of an artificially expanded definition. The testimony of Dr. Tabors shows that by expanding the definition of spot market to include contracts of a year or more, these claimants increased their potential claim by a magnitude of more than ten:

> My Exhibit PWX-13 quantifies the impact of applying this definition [of spot market] to the refund claims of … NPG entities who are serving load in the Northwest…. This exhibit shows that *94%* of these NPG claims are eliminated if the proper definition of a spot market transaction is applied as a screen to their purchase data during the potential refund period (December 25, 2000 through June 20, 2001). This reduces the total claims … from *$460,668,382* to *$25,410,505*.

Exh. PWX-12 at 5:12-18 (emphasis in original); *see also* Exh. TFG-23A. Dr. Tabors again notes this correlation:

It is interesting to note that only 1% of Seattle City Light's proposed refunds are attributable to its spot purchases and well less than 40% of Tacoma's refunds are due to its spot purchases. *Thus, the bulk of the refunds they are seeking are attributable to the prices they paid under their forward contracts!*

Exh. PWX-1 at 23:6-9 (emphasis in original).

Additionally, TFG argues, NPG asserts that the cross-examination of NPG witness Ms. Green revealed the existence of important differences between daily market transactions and month-ahead or longer transactions: "Under traditional practice, none of the hourly transactions are [sic] recorded on paper. There simply isn't time to deal with that…. [In contrast,] monthly deals do have written confirmation." Tr. at 582:14-16, 1-4.. Ms. Green also admitted that the City of Seattle has different personnel assigned to the "forward" desk to conduct these different functions. Tr. at 580:9-581:19. The Deputy Director of California Department of Water Resources, who professed "quite extensive" on-the-job experience, defined spot market as "normally 24 hours or less." Tr. at 986:9-10; 898:14-18; *see also id.* at 902:21-904:3; 916:6-917:3.

Dr. Tabors explained that spot market contracts and forward contracts have different characteristics. He corrected the Staff's contention that spot market could mean up to one year:

> Staff has focused on price to the exclusion of all other contract terms and conditions, such as quantity and availability of supply. For example, as I stated in my responsive testimony, the fact that a forward contract has an indexed price does not serve to convert the forward contract into a spot contract.

Exh. PWX-12 at 9:13-16.

In further support of its contentions, TFG avers that Mr. Stelzer, trading manager of Avista Energy's power trading activities, explained that "the bilateral wholesale electric market is broken down into the term (or forward) market and the spot market which encompasses the day-ahead and real-time market." Exh. AE-1 at 7:15-17. He described the types of products in the forward market which are not considered spot but which are for delivery terms of greater than 24 hours. "This [forward] market includes: weekly products, balance-of-the-month products, monthly products, quarterly products, annual products and multi-year products." Exh. AE-1 at 7:21-22.

Dr. Tabors' testimony illustrated the significant differences between spot market transactions and forward contracts:

> A spot market bilateral contract for electricity differs from a forward market bilateral contract for electricity in many respects, and therefore represents a different "product" from the perspective of both a buyer and a seller. These differences include:
>
> • Timing of the contractual commitment. Spot market transactions are entered the day-of or day-prior to delivery, forward market transactions may be entered days to years prior to delivery.
>
> - Duration of the commitment. Spot market transactions are 24 hours or less, forward market transactions may be for multiple years.
>
> - The hours in which electricity will be delivered. Spot market transactions provide for deliveries in a specific hour or hours up to 24 hours in advance. Forward market transactions provide for deliveries in blocks of heavy load hours (HLH), light load hours (LLH) or all hours (flat) for durations of balance of month, month, quarter, annual or multiple years.
>
> - [Physical Delivery.] Spot market contracts almost always go to delivery whereas forward contracts can be, and frequently are, traded several times prior to delivery. This ability to trade forward contracts gives their buyers the ability to continuously "fine tune" their portfolio of advance supplies to match changing expectations regarding their actual requirements and the availability of other resources to meet those requirements.

As a result of these key differences, the value of electricity under each type of transaction will be different. The Commission recognized the differences in value between spot market transactions and forward market transactions in its December 15 Order. Thus, it is unlikely that in any given hour a buyer with a portfolio of contracts will be paying the same price for electricity bought under a bilateral spot market contract as it is paying for electricity bought under a bilateral forward contract, even if it is buying the identical quantity in each market in a given hour from the same seller. Exh. PWX-1 at 24-25.

According to TFG, Mr. Stelzer further distinguished a spot market contract from a forward contract with a pricing mechanism indexed or referenced to spot prices:

> Volume and other essential terms in an indexed contract are decided on a long-term basis and the buyer has simply and voluntarily chosen a pricing option (one among many) in a long-term contract which has some reference to the spot market. Where a buyer elects to have its purchases under a long-term contract indexed to the spot market, the buyer may believe that the price for this product in the forward market is higher than what the price of the spot market will be when the electricity is actually delivered. Alternatively, the buyer may not be concerned so much about price as it is about electricity not being available when it comes time to buy . . . and elects to lock-in delivery under the forward contract.

Exh. AE-1 at 10:16-11:2. Finally, Mr. Oliver from BPA, in describing the contract underlying the refund claim of Northern Wasco County People's Utility District ("Northern Wasco") explains:

> Northern Wasco elected . . . to serve approximately 30% of its firm load needs through a surplus firm power sale agreement providing for the purchase of a cost-based product that had a price tied to the Mid-Columbia Index . . . because they thought this rate would be lower than the cost-based federal power over the long run. These contracts are not spot market transactions. They are long-term firm power contracts that were indexed to spot market, at the election of Northern Wasco.

Exh. BPA-1 at 8.

Evidence of record, TFG maintains, confirms the customary and proper definition of "spot market." It means sales for immediate delivery; it is distinct from other products. Immediate delivery in the PNW is defined by scheduling practices. Thus, TFG alleges, the evidence demonstrates that for the PNW wholesale electrical market, "spot market" sales are those sales made 24 hours or less in advance of delivery for a duration of 24 hours or less, except for holidays, weekends or scheduling coordinator conferences, but delivery is nonetheless scheduled immediately. No other reasonable or credible definition has been established.

TFG also argues that both the evidence and the issues stipulated establish that the region specified by the Pacific Northwest Electric Power Planning and Conservation Act is the pertinent geographic market. That market is:

> (A) the area consisting of the States of Oregon, Washington, and Idaho, the portion of the State of Montana west of the Continental Divide, and such portions of the States of Nevada, Utah, and Wyoming as are within the Columbia River drainage basin; and
>
> (B) Any contiguous areas, not in excess of seventy-five air miles from the area referred to in subparagraph (A) which are a part of the service area of a rural electric cooperative customer served by the Administrator on December 5, 1980 which has a distribution system from which it serves both within and without such region.
> 16 U.S.C. § 839a(14).

According to TFG, the testimony presented here establishes that this definition informs and guides the conduct of market participants. This is the same definition that Puget used in its Complaint initiating this proceeding. *See* Exh. ENR-1 at 4:19-5:3. As Mr. Van Vactor explained, "[t]his definition of the PNW power market is the most consistent and useful [because it] both matches the operational characteristics of the power system and waterways and also conforms to the existing political organization of the region." *Id.* at 5:14-18. Mr. Van Vactor explained that, the NW Power Planning Act defined market is the appropriate choice here because it:

> encompasses the entirety of the U.S. portion of the Columbia River drainage basin, which is the principal source of generation for the Northwest's utilities, a major transportation waterway, the most important source of irrigation supporting the region's agricultural industry, and a key natural

> resource for recreation and preservation of wildlife. In short, the management of rivers and the coordination of hydroelectric generation are activities that necessitate region-wide planning and cooperation for the states adjacent to the Columbia River, but need not involve other parts of the western region. In addition, the NW Power Planning Act established the Northwest Power Planning Council with representatives appointed by the Governors of Idaho, Montana, Oregon, and Washington. The Council is responsible for preparing Northwest Power Plans at least every five years. The most recent was completed in 1998. The principal reasons for these plans are to ensure that generating resources and loads in the region are balanced cost effectively, energy conservation programs are implemented, and, recently, that wild salmon runs on the Columbia River and its tributaries are preserved and enhanced.

Id. at 5:19-6:10.

As Mr. Van Vactor further explained, the testimony suggesting a geographic definition other than that prescribed by NW Power Planning Act is misguided:

> The justification of City of Seattle's witness, Robert McCullough, for using a broader definition, the Northwest Power Planning Pool ("NWPP") as opposed to the "PNW" in the NW Power Planning Act is problematic. Parts of the NWPP are more heavily traded by Southwest and Southern California utilities than by Northwest utilities. The Intermountain Power Project, for instance, sends a substantial amount of power (approximately 1,500 MW per hour) to the Los Angeles control area even though it is located in Utah, and hence is in the NWPP.
>
> Furthermore, all of the PNW refund proponents are located within the territory governed by the NW Power Planning Act (with the obvious exception of the California parties who are decidedly not PNW utilities); thus, adopting the broader definition of the NWPP would unnecessarily expand the investigation envisioned by the evidentiary hearing.

Exh. ENR-1 at 6:13-24.

TFG further maintains, notably, as Mr. Ali Yazdi explained, the definition of PNW "should be qualified as a practical matter to exclude southbound transactions at the COB and NOB delivery points for CDWR's account." Exh. PWX-7a at 5:16-18. This is because

> [t]hese transactions are really transactions for California loads that happen to specify a delivery point at the PNW-California boundary. The PNW delivery point in the case of CDWR transactions was based on transmission rather than load-serving considerations.

Id. at 5:18-6:2.

California Parties' witness Mr. Green of the California Energy Resource Scheduling Division ("CERS")[58] also admitted that COB deliveries in reality are made at the California border and that the ISO tariff specifies scheduling points for such deliveries as "Malin-[Oregon]", "Round Mountain [California]" and "Captain Jack [Oregon], Olinda [California]." Tr. at 876:3-12. Mr. Green also testified that NOB is an "imaginary" point and that NOB deliveries actually take place in California at the control area of the Los Angeles Department of Water and Power. Tr. at 876:16-25.

In further support of its arguments, TFG points out that no one seriously disputed the definition of the PNW at the hearing. Cross-examination of Mr. Van Vactor and the other witnesses expressing the same geographic market definition did not in any way undermine their view or the logic of it. The Staff witness testifying as to market definitions similarly offered no contrary view of the proper geographic market:

> As stated in the Commission's June 19, 2001 Order and as stipulated by the parties in the instant proceeding (this portion of the Stipulation was incorporated in the Presiding Judge's August 23, 2001, order on issues), the Pacific Northwest is defined in the Pacific Northwest Electric Planning and Conservation Act, 16 U.S.C. § 839a(14). Exh. S-1 at 8:5-8.

Therefore, according to TFG, the evidence proves that the correct definition of the PNW is the geographic region defined in the NW Power Planning Act and that southbound flows at COB and NOB are not sales "into" the PNW, but into California. Thus, these California transactions should not be considered in this PNW proceeding, as discussed in detail in Section V of this brief.

Concerning the refund claims of the California Parties TFG avers that the

---

[58] CERS is a division of the CDWR that is authorized by California statute "to purchase electric power and sell power to retail end use customers and to locally publicly owned electric utilities." Exh. CAL-1 at 3:8-9.

California Parties[59] have made refund claims on behalf of the CDWR, which does not itself seek refunds. Tr. at 843:11-23. The California Parties base these claims on CDWR purchases and exchanges under bilateral agreements (not limited to spot market transactions) which they allege to have occurred in the PNW during the potential refund period.

The TFG opposes these refund claims. The California Parties' claims have already been rejected by the Commission in Docket No. EL00-95 and do not reflect the stated position of CDWR, the entity on whose behalf they are ostensibly being brought. TFG believes that the California Parties' claims have no place in this proceeding. If these claims are considered at all in Docket No. EL01-10, they should be disallowed.

This preliminary evidentiary proceeding was intended by the Commission to give PNW parties claiming refunds or asserting offsets in Docket No. EL00-95 additional process to demonstrate whether their claims warranted further proceedings. TFG argues, unlike the PNW parties, the California Parties fully ventilated their refund claims in Docket Nos. EL00-95. The Commission was unpersuaded, and expressly denied relief for CDWR's bilateral purchases on both legal and equitable grounds.[60]

The TFG sought to strike the California Parties' direct case,[61] but the Presiding Judge gave the California Parties an opportunity to participate in the hearing.[62] The Presiding Judge now has an evidentiary record upon which to make a preliminary ruling on the California claims and give effect to her earlier warning that "California refunds are being litigated in a separate proceeding, EL00-95-031, *et al*.TFG contends."[63]

By order dated August 8, 2001, the Presiding Judge aligned the following five California parties with the Pacific Northwest Net Purchasers Group ("NPG"): the CAG,

---

59 Nominally, the California Attorney General ("CAG"), the California Public Utilities Commission ("CPUC") and the California Electricity Oversight Board ("EOB").

60 July 25 Order, 96 FERC at 61,514-515.

61 Motion of the Transaction Finality Group to Strike Testimony of California Parties, Docket No. EL01-10 (August 22, 2001).

62 Order on Motion to Strike Testimony, Docket No. EL01-10 (August 24, 2001).

63 Order on Format for Data Submissions, Docket No. EL01-10 at 8, n.7 (August 9, 2001).

the CPUC, the California Independent System Operator ("CAISO"), the EOB and Southern California Edison Company ("SCE"). Another California Executive Branch entity (CDWR—the real party in interest under the bilateral agreements), never sought to intervene in this proceeding.[64] Ultimately, only three of the five named "California Parties"—the CAG, the CPUC, and the EOB – were part of the group's August 17, 2001 affirmative case filing.

According to TFG, the California Parties allege that a total of $2.64 billion of purchases by CDWR falls within the scope of this Docket No. EL01-10 proceeding, of which they claim $1.47 billion in refunds. To support this claim, the California Parties presented testimony of one fact witness, William Green, and one economic witness, Dr. Frank Wolak. Mr. Green, an employee of the California Energy Resources Scheduling ("CERS") Division of the CDWR, testified that the entirety of the California Parties' claim was based on bilateral purchases made by a single entity, the CDWR.

In his direct testimony, and again at hearing, Mr. Green stated that he had aggregated, for refund claim purposes, *all* transactions (including longer-term arrangements, fixed price arrangements, aggregation or "sleeving" arrangements, and exchanges) where California took power at one of its interconnects with the PNW. According to Mr. Green, CDWR treated all these transactions as spot market transactions under the Staff's template definition, based on the time the deliveries were scheduled (*i.e*., day-ahead or in real-time), without regard for the related contracts, Transaction Confirmations or negotiated arrangements under which such deliveries occurred, or indeed, for the duration of the transactions themselves. *See* Exh. CAL-1 at 5.

Dr. Wolak's testimony, TFG avers, summarized the California Parties' position on the appropriateness of refunds for these transactions. Dr. Wolak opined that refunds should be considered for all transactions up to two years in duration. In addition, Dr. Wolak also made generalized allegations that sellers had exercised market power, but neither he nor any other California witness provided any evidence of actual or attempted exercise of market power by any seller in the PNW.

---

[64] CERS is not an intervenor either. As a division of CDWR, CERS has no separate legal standing. CDWR itself, not CERS, is the member of WSPP and signatory to the contracts and Transaction Confirmations at issue in this proceeding. CERS may have scheduled deliveries under these agreements (in improper concert with the ISO), but CDWR is the real party in interest in this proceeding.

On rebuttal, the California Parties supplemented the additional testimony of Mr. Green with one additional fact witness, Mr. Raymond Hart, the Deputy Director of CDWR and the Director of CERS during the potential refund period, and one additional economic witness, Dr. Carl Pechman. According to TFG, Mr. Hart detailed CDWR's version of the events surrounding the agency's purchases (principally from Powerex Corp. ("Powerex"), a TFG member) in early 2001, and discussed the credit and payment terms insisted on by Powerex. Dr. Pechman attempted to refute the testimony of the TFG's experts, who had testified why, for economic and policy reasons, refunds are not appropriate for the bilateral purchases which fall within the scope of this proceeding. Dr. Pechman also made unsubstantiated assertions regarding in elasticity of demand, even though he admitted he had performed no studies in that regard. In fact, demand in the PNW behaved in just the opposite fashion from what he suggested. Mr. Green, Mr. Hart and Dr. Pechman were all cross-examined at hearing by the TFG and others.

According to TFG, there is abundant record evidence in this proceeding showing not only that sales to CDWR should not be considered in this proceeding along with true PNW transactions, but also that the CDWR transactions upon which the California Parties have based much of their refund claims, are not spot market bilateral sales. This evidence, discussed in detail below, clearly supports a finding by the Presiding Judge that the refunds sought by the California Parties should be disallowed.

TFG argues that the Commission's refund authority in Docket No. EL01-10 is constrained under Section 206 of the Federal Power Act by the date and substance of Puget's October 26, 2000 complaint.[65] Puget's complaint was expressly limited to contracts for sales *into* the PNW market:

> [T]his Complaint seeks an order affecting the market-based rate schedules of wholesale sellers of energy and/or capacity *into* electric energy and/or capacity markets in the Pacific Northwest … (Complaint, at 1) (emphasis added).

By formal notice issued October 31, 2000, the Commission identified Puget's complaint as addressing the prices at which sellers "may sell capacity or energy *into* the Pacific Northwest's wholesale power markets."

---

[65] July 25 Order, 96 FERC at 61,520 n.75 ("December 25, 2000 is the earliest refund effective date the Commission could establish for Puget's complaint regarding rates in the Pacific Northwest").

In orders issued in EL00-95, the Commission has clearly and carefully delineated the scope of its refund authority:

> We conclude that FPA section 206 does not permit the Commission to require refunds of unjust and unreasonable rates charged prior to a date 60 days after the filing of a complaint or 60 days after the initiation of a Commission investigation on its own motion. To order such refunds would contravene explicit refund limitations that Congress put in FPA section 206.[66]

No complaint has ever been filed with the Commission, nor has any notice ever been issued by the Commission, stating that *any* sales under CDWR's bilateral contracts may be subject to refund prior to June 20, 2001. Under the Commission's June 19, 2001 order in Docket No. EL00-95, only CDWR spot market transactions were made subject to market mitigation (along with all other bilateral spot market transactions in the WSCC) prospectively from June 20, 2001. The extension of Docket No. EL01-10 to include CDWR's bilateral contracts—contracts for sales of energy or capacity *into California*—would constitute an unlawful extension of the Commission's Section 206 refund authority. Recognizing this in its July 25 Order, the Commission invited CDWR to file its own Section 206 complaint in the event it wished to contend that its bilateral contracts were unjust and unreasonable.[67] CDWR has not done so. Thus under Section 206 of the FPA, there is no legal basis for the Commission to order retroactive refunds with respect to CDWR's bilateral transactions.

In its July 25 Order, the Commission flatly refused to order refunds with respect to CDWR's bilateral agreements. The Commission concluded that:

> . . . imposing after-the fact refund liability on California transactions outside of the centralized ISO and PX markets is unjustified. This is particularly true in the instant proceeding [Docket No. EL00-95] when the Commission consistently encouraged California load-serving entities to acquire a balanced portfolio of short, medium-term and long-term contracts. Expanding the scope of transactions subject to refund over the period October 2, 2000 through June 20, 2001 to include transactions outside the ISO and PX markets

---

[66] July 25 Order, 96 FERC at 61,504.

[67] 96 FERC at 61,515 n. 59.

> would simply hinder the ability of parties to enter into new bilateral contracts.[68]

Until this PNW hearing in Docket No. EL01-10 was initiated, there was no suggestion whatsoever from the California Parties that CDWR's bilateral transactions were anything other than California transactions subject to the proceedings in Docket No. EL00-95. Since the Commission expressly determined in the July 25 Order that refunds under CDWR's bilateral agreements were unjustified, it inexorably follows as a matter of law that CDWR's bilateral contracts with PNW sellers for deliveries to points on the boundaries of the PNW and California, for consumption within California, cannot be subject to refunds in Docket No. EL01-10.

The California Parties' attempt to repackage selected CDWR transactions into a new PNW category is belied by their own pleadings in the two dockets, TFG argues. In its July 30, 2001 rehearing request (filed in Docket No. EL00-95 one day before the first prehearing conference in Docket No. EL01-10), the EOB sought reversal of the Commission's decision in Docket No. EL00-95 to deny refunds with respect to *all* CDWR bilateral spot market transactions. In its rehearing request, the EOB drew no distinctions whatsoever based on the point of delivery or the point of origin. Table 2 of the EOB's rehearing request referred to CDWR's alleged January 2001 purchases from PNW Parties (including TFG members Avista, Coral Energy and Powerex Corp.) as justifying a retroactive refund finding by the Commission on rehearing.[69] Plainly, EOB viewed these CDWR bilateral transactions with PNW parties as being within the scope of the Commission's ruling denying refunds in Docket Nos. EL00-95. Otherwise, EOB would not have included them in its rehearing request.

The California Parties cannot have it both ways, TFG maintains. In Docket No. EL00-95, EOB and the other California Parties repeatedly asserted refund claims based on the totality of the CAISO, California PX and CDWR transactions from May 1, 2000 to date. All of these transactions were subsumed in Governor Davis's $8.9 billion refund claim, which was asserted in the settlement discussions before Judge Wagner by Michael Kahn, Chairman of the ISO, speaking on behalf of CDWR, the CAG, the CPUC and the EOB, among others. The only rational way to harmonize the Commission's July 25th Order—which on one hand expressly denies refunds for CDWR's bilateral transactions and directs CDWR to file a complaint if it has a problem, and on the other hand

---

[68] 96 FERC at 61,515.

[69] *See* EOB Rehearing Request, Docket Nos. EL00-95 et al., at 14 (July 30, 2001).

establishes a preliminary evidentiary proceeding to review potential refund and payment claims by PNW parties—is to construe the Docket No. EL01-10 proceeding as excluding CDWR bilateral transactions, and as being limited in scope to the transactions addressed in Puget's original complaint.

There is also no factual basis for considering CDWR's transactions in this PNW-specific preliminary evidentiary proceeding. The Commission's sole purpose for instituting this hearing was to give PNW Parties that participated in the June 25 - July 9 settlement discussions before Chief Judge Wagner "additional process" to discuss amounts owed and refunds claimed to be due to them. As Judge Wagner noted in his July 12, 2001 report to the Commission,[70] these settlement discussions dealt almost exclusively with California refund claims—*including* refund claims regarding CDWR bilateral purchases.[71]

The Commission has made its intent abundantly clear in the July 25 Order:

> The Chief Judge noted that there was little time to address the issues raised by the Pacific Northwest Parties. Moreover, these parties did not have data on what they claim they were owed, nor on an amount of refunds due them. The Chief Judge requested comments on the necessity of convening subsequent settlement conferences to address the issues. Comments jointly filed by the Pacific Northwest Net Purchasers state that there was inadequate time either to document the harm suffered, or to engage in meaningful settlement discussions with affected sellers. Given these circumstances, they request additional process on this matter.[72]

As counsel for PacifiCorp, speaking on behalf of the Pacific Northwest Net Purchasers Group, stated to Judge Wagner in a public hearing held late on July 9, the last day of the settlement conferences:

---

[70] *San Diego Gas & Electric Co., et al.*, 96 FERC ¶ 63,007 at 65,039 (2001).

[71] The California Parties (and other California entities such as the CAISO, Pacific Gas & Electric Company, Southern California Edison Company and San Diego Gas & Electric Company) operated as a separate and distinct group throughout these settlement discussions, and were not treated by Judge Wagner or the other parties as being associated in any way with Pacific Northwest issues.

[72] 96 FERC at 61,520.

> We respectfully request that as part of your recommendations, that the Commission find a way to extend the proceedings so that Northwest refunds can be considered in parallel to those enjoyed by consumers in the State of California.[73]

There is nothing in the record that Judge Wagner compiled, in Judge Wagner's Report, or in the Commission's discussion of the Pacific Northwest proceeding in the July 25 Order to suggest that the Commission intended for CDWR bilateral transactions for which refunds were denied in Docket No. EL00-95 to be revisited in Docket No. EL01-10. On the contrary, the Commission took pains to distinguish this Pacific Northwest proceeding from the California proceedings:

> In light of the complexities associated with these retroactive bilateral calculations and the absence of any further development of this issue in the settlement proceeding, and in recognition that the prior settlement proceeding focused primarily on California, *we will establish a separate preliminary evidentiary proceeding pertaining to the Northwest.* [74]

In furtherance of its contentions, TFG argues that CDWR was authorized by California statute[75] in February 2001 to begin purchasing electric power to sell to retail end-use customers *in California* and to make purchases on behalf of the three *California* IOUs, including their net short position.[76] Exh. CAL-1 at 3. There is no suggestion in the record that CDWR has been anything other than a purely California entity since it commenced operations. By no stretch of the imagination could it be considered to be a PNW party.

Since January 17, 2001, CDWR has been the power procurement agency for the state of California. Tr. at 808:19-09:8. The agency makes purchases solely for California entities. It does not make purchases for consumers outside California. Tr. at 875:10-12. It maintains no offices or operations in the PNW. Tr. at 874:20-75:5. CDWR does not contract for transmission in the PNW or anywhere outside of

---

73 July 9, 2001 Hearing in Docket Nos. EL00-95 *et al*., Hearing Tr. 682.

74 96 FERC at 61,520 (emphasis added).

75 This enabling legislation for CDWR’s power procurement function is known as “AB-1X,” and is contained in Exh. TFG-14. AB-1X makes no mention of CERS.

76 2000 Cal. Legis. Serv. 1ES 4 (West) § 80100 *et seq*. (“AB-1X)”, TFG-14, at 6.

California.[77] Tr. at 895:2-7. Its sole nexus to the PNW is that certain of its transactions specify delivery points at interconnects on the boundaries of the PNW with California (COB, NOB, Cascade and Summit). Tr. at 877:21-878:1. However, CDWR actually takes physical delivery of its purchases at substations located *within California* "Malin-5-Round Mountain" and "Captain Jack-5-Olinda" in the case of COB, and a substation within LADWP's control area in the case of NOB. Tr. at 875:19-877:3. In short, there is no factual basis to conclude that CDWR is a PNW party entitled to have its claims considered in Docket No. EL01-10.

All purchases that the California Parties have categorized as PNW purchases were made under the framework of the WSPP Agreement. Tr. at 889:8-12. CDWR is a member of the WSPP. Tr. at 890:25-891:1. The terms of the WSPP Agreement have been reviewed and approved by the Commission. Tr. at 891:2-6. Section 35 of the WSPP Agreement specifically provides that all transactions under the WSPP Agreement, together with the confirmation agreements executed pursuant to its terms, are considered forward contracts. Exh. S-6 at Original Sheet 56; Tr. at 890:13-18.

The Commission has ordered that the PNW transactions to be examined in this proceeding are limited to spot market bilateral sales in the PNW.[78] TFG further argues, that notwithstanding that all transactions entered into under the umbrella of the WSPP agreement are considered forward contracts, the California Parties apparently allege that all transactions that CDWR entered into under the umbrella of the WSPP Agreement in fact constitute spot market purchases.[79] Thus any transaction *scheduled* by CDWR within 24 hours of delivery (which would encompass literally any delivery under a forward contract) has been treated by the California Parties as a spot market purchase, without regard for either the WSPP Agreement, when related Transaction Confirmations under the WSPP Agreement may have been entered into, or the nature of the ongoing relationships between CDWR and its counterparties. This severely distorts and inflates the extent of the California Parties' claimed refunds.

For example, TFG avers, Dr. Tabors analyzed CDWR's data regarding purchases from Powerex (which accounts for more than a third of the California Parties' refund

---

[77] This is LADWP's Sylmar Substation.

[78] July 25 Order, 96 FERC ¶ 61,120 at 44.

[79] If the California Parties are not in fact calling such transactions "spot market" transactions, then they are simply disregarding yet another clear dictate of the July 25 Order, which limited the scope of this proceeding to spot market bilateral sales.

claims), and applied a proper definition of a spot market transaction as a filter for such data (transactions of 24 hours or less, entered into the day of or day prior to delivery). Dr. Tabors showed that applying this definition to CDWR's data reduced the California Parties' refund claims against Powerex by 86 to 90 percent, from $568,240,374 to between $57 million and $80 million. Exh. PWX-12 at 6-7. Dr. Tabors did not have time under the compressed procedural schedule to perform this calculation with respect to CDWR's refund claims against other sellers, but TFG notes that the California Parties did not question Dr. Tabors' conclusions on cross-examination.

The validity of the California Parties' claims is further compromised by their inconsistent and conflicting positions regarding what constitutes a spot market transaction—a core issue in both the PNW and California dockets, TFG asserts. For example, in the EOB's July 30, 2001 request for rehearing in Docket No. EL00-95, the EOB acknowledged that CDWR defines the spot market as "day-ahead purchases, hour-ahead purchases, and ISO real-time purchases."[80] In contrast, Dr. Frank Wolak, the California Parties' expert witness in EL01-10, although not directly addressing the issue of what constitutes a spot market, opined that for litigation purposes the "appropriate time horizon . . . that a bilateral sale of electricity in the Pacific Northwest market that should be subject to refund is as long as two years in advance of the delivery date."[81] Exh. CAL-5 at 4.

Mr. Green, according to TFG, also put forward shifting definitions of the spot market, and created further confusion regarding the true nature of the transactions reflected in his Exh. CAL-11 and associated confidential workpapers. ***(Confidential Exhibit TFG-19 in the case of CDWR transactions with Powerex, a TFG member)*** Mr. Green in his direct testimony originally stated that "almost all our purchases were for 24 hours or less." Exh. CAL-1 at 4. Mr. Green then went on to list the "aggregate" CDWR transactions that occurred at PNW delivery points. Mr. Green broke out these transactions by Out Of Market ("OOM"), Day-Ahead and Long/Short categories, with

---

80 Request of the California Electricity Oversight Board for Expedited rehearing of the July 25 Order Establishing Evidentiary Hearing Procedures, Docket Nos. EL00-95-004 *et al.*, at 13 n. 7 (July 31, 2001).

81 Dr. Wolak stops short of calling such transactions "spot market" transactions and instead speaks in terms of transactions that "should" be subject to refund. The July 25 Order did not, however, invite such an inquiry into what "should" be subject to refund. Instead, the order referred specifically to potential refunds in connection with *spot market* transactions. July 25 Order, 96 FERC at 61,520.

the preponderance of claimed refunds arising from the OOM category of transactions. The inference created by Mr. Green's testimony was that most of the OOM transactions were periods of 24 hours or less, and hence were eligible for refunds. However, on cross-examination Mr. Green qualified his testimony by stating that he "normally" defined "spot market transactions" as "24 hours or less," Tr. at 898:17-18, and then went on to relate his categorizations of CDWR transactions to the Staff's data template (which was not intended to define the term "spot market") rather than to any assessment of the actual character of the transactions themselves. Tr. at 902:21-903:1. On redirect, Mr. Green tried to conform his testimony and the workpapers to the California Parties' position in EL01-10, by stating that "[W]hen there's conditions such as shortness of supply, a spot term might be quite a bit longer than 24 hours or one day . . . Could be the balance of the month or a whole month or longer. . ." Tr. at 981:1-6.

TFG contends that the inflated data, conflicting positions of the California Parties, and vagueness of Mr. Green's testimony fatally undermine the factual basis for their refund claims. These defects in CDWR's claims, TFG argues, render Mr. Green's testimony and exhibits unreliable and non-probative. The only conclusions that the Commission can draw are that the California Parties have failed to provide probative evidence to support their refund claims and meet their burden of proof in this proceeding, and that their proposed definition of the "spot market" is inconsistent with the overwhelming weight of the evidence in the record.

According to TFG, the California Legislature, in enacting AB-1X, gave CDWR the sole authority to determine the justness and reasonableness of its power purchases under Section 451 of the Public Utility Code of California, without review by the CPUC or any other regulatory body.[82] The CPUC has expressly acknowledged that "contracts for and purchases of power by DWR and related indebtedness are not subject to [CPUC's] reasonableness review." Exh. TFG-15 (CPUC Decision No. 01-03-009, March 7, 2001). On cross-examination, Mr. Hart confirmed that CDWR is self-regulating with respect to its purchasing activities. Tr. at 840:12-17.

As noted above, CDWR itself does not seek refunds in this proceeding. Also, CDWR has not filed a complaint at FERC regarding any of its bilateral purchases, nor has CDWR issued any notice of potential refunds under AB-1X with respect to its

---

[82] *See* AB-1X § 80110; *see also* Exh. TFG-14 at 7-8.

purchases.[83] Instead, Mr. Hart, as "fact witness" for the California Parties, has only offered his personal opinion that CDWR had “no choice” but to purchase power from PNW sellers such as Powerex, Exh. CAL-9 at 2, 3, 6, paid too much for the power, *see, e.g.*, Tr. at 897:19-21, and paid prices for power that reflected sellers’ “opportunity costs to make a fortune off some poor chump like me.” Tr. at 947:23-24. Recross of Mr. Hart demonstrated that he is not qualified to testify as an economic expert on the subject of market power. Tr. at 985:21-987:11. The California Parties’ economic expert, Dr. Wolak, made only generalized allegations of exercise of market power by sellers in California and the PNW, but offered no proof whatsoever in support of his assertions.

Thus, reduced to its essence, the California Parties’ refund case is based on Mr. Hart’s assertions that he paid too much to sellers, even though his employer, CDWR, does not itself seek refunds for the purchases Mr. Hart and his staff made. Mr. Hart is entitled to his observations, but they do not constitute evidence that the prices CDWR paid for power purchased from PNW sellers during the potential refund period were unjust and unreasonable.

To the contrary, TFG asserts, there is ample record support justifying the prices paid by CDWR to PNW sellers. Because of the circumstances it confronted in California,[84] CDWR, a state agency, found it necessary to purchase large, even huge, blocks of power on a recurring basis to meet peak and super-peak needs, and in so doing had to draw on other utility systems outside of California to meet demand. In the PNW, for example, CDWR relied on the ability of hydroelectric systems such as those operated by BPA and BC Hydro (Powerex’s parent) to produce large blocks of power on short notice. Tr. at 892:23-893:12.

Through these arrangements, CDWR was able to purchase blocks of power as much as 2,000 MW to 3,000 MW, and to purchase large blocks of power on a recurring basis throughout the refund period. Tr. 893:17-21.

---

[83] Under the same principles that constrain FERC, CPUC regulatory actions under Section 451 of the California Public Utilities Code are subject to the filed rate doctrine and prohibitions against retroactive ratemaking. *Pacific Tel. & Tel. Co. v. Public Util. Comm.*, 62 C.2d 634 (1965). Since AB-1X confers this same Section 451 rate review authority on CDWR with respect to its purchases, the same ratemaking standards apply to CDWR.

[84] The factors that led to CDWR’s demand for power are chronicled by Powerex’s witness Mr. Peterson in Exh. PWX-6 at 11.

What Mr. Hart failed to point out is that the ability of hydropower generators to provide these large blocks of power on short notice is not infinitely elastic, and involves considerations of opportunity costs and the cost of replacement power, TFG contends. In his Prepared Responsive Testimony on the Nature of Hydroelectric Power, Dr. Tabors discusses in detail how hydropower systems operate, including their ability to ramp unit output up and down quickly to meet rapid changes in load from hour to hour. Exh. TFG-5 at 4. However, responding to such changes in demand can lead to decreased efficiency of the hydropower resource, increased water use and loss of operational flexibility. *Id.* at 6-7. In making such deliveries off-system (such as to CDWR), a hydropower generator has "to charge a price that is related to the forward price of energy to have any degree of certainty that what it is selling today will not cost the operator more to replace tomorrow." *Id.* at 4. This is especially true in a deficit water year such as 2001. *Id.* at 3. As stated by Dr. Tabors:

> The sales price of hydroelectric energy by Powerex in one month needs to be evaluated by reference not to the prevailing price of energy at the time the sale occurred, nor to a theoretical market price based on thermal generation and the price of natural gas, but rather to the opportunity cost or value of the energy at any point in the future. The best indicator of this value is the forward market price for electricity. This temporal nature of hydroelectric production must be considered in any refund calculation, if the Commission retroactively determines that overcharges have occurred.

Id. at 8.

For example, Powerex's witness Mr. Peterson in his direct testimony stated that Powerex relied on the August 2001 forward market price for electricity when it entered into the fixed price arrangement under which CDWR purchased large blocks of power from January 17, 2001 until near the end of the potential refund period. *See* Exh. PWX-6 at 15. Dr. Tabors also testified to the transmission risks confronted by hydropower generators making off-system sales, and observed that in acquiring replacement power in the PNW, hydropower generators faced the same market, climatic and water conditions as other PNW purchasers (and CDWR). Exh. PWX-5 at 6.

It is inappropriate, according to TFG, and contrary to the record evidence in this proceeding, for Mr. Hart to seek to treat these capacity-backed transactions, whereby CDWR was able to draw repeatedly on the generation capabilities of these hydropower systems for large blocks of power to make up for the deficiencies of its own power purchase portfolio and keep its system in balance, as no better than spot transactions. In effect, CDWR found it necessary to rely repeatedly on these other utility systems in order to make up for the generation shortfall that California had managed to create for itself.

Moreover, Mr. Hart has ignored CDWR's own position regarding opportunity costs and the costs of replacement power for hydropower producers in making his overcharge claims, TFG alleges. Incorporated as an item by reference in this proceeding, Exhibit TFG-23 consists of the comments filed by CDWR in Docket No. EL00-95 on March 23, 2001. With respect to the pricing of CDWR's own hydropower production for sales to the ISO, CDWR stated:

> Further, developing the marginal cost of hydrogeneration and the criteria for dispatch by the ISO for such units as imbalance energy is more difficult and *needs to consider the lost opportunity in calling upon such generation at a particular time* by the ISO, *i.e.*, the fuel (water) may not be replaceable once used and there could be a greater value for the generation at a later time.[85]

The only other allegations made by Mr. Hart to support his refund claims were what he referred to as "draconian" payment and credit terms imposed by Powerex. However, the record shows that these terms were fully justified by the "spooky" credit situation surrounding CDWR. Tr. at 859:23-860:3. At the time CDWR began purchasing from Powerex, the ISO and the CalPX owed Powerex some $300 million, which has still not been paid. Exh. PWX-6 at 9. On or about the time CDWR commenced its power purchasing operations for the State of California, Governor Davis commandeered some $1.1 billion in collateral that had been pledged as security to the CalPX, the ISO made its first default to sellers, and the CalPX made its first default to sellers and then went bankrupt. Tr. at 859:5-22. Also, PG&E subsequently filed for bankruptcy in April 2001.

Moreover, TFG argues, during the course of the potential refund period, CDWR's purchases were expressly *not* backed by the full faith and credit of the State of California, and CDWR was existing hand-to-mouth on a series of draws in $500 million increments from the General Fund of California (which have never been repaid), that lasted only as long as a "very few days" in many instances. Tr. at 854:19-21. Additionally, two of the three principal CDWR funding mechanisms prescribed by AB-1X (the CPUC's allocation of a designated portion of the IOUs' retail revenue stream to CDWR's Electric Power Fund, and CDWR's $13 billion bond issue) had not been implemented. Tr. at

---

85 Comments of the California Department of Water Resources, Docket No. EL00-95-012 (Mar. 23, 2001), TFG-23 at 6 (emphasis added).

851:22-853:13. In view of all these circumstances, and CDWR's refusal to furnish a letter of credit and its inability to obtain the equivalent of a parental guaranty from the State (both of which are common credit assurance devices in the power industry), Tr. at 862:5-863:20, the credit and payment terms imposed on CDWR by Powerex were not draconian, but in fact reasonable, and even generous considering the circumstances.[86]

Apart from Mr. Hart's assertions regarding the high prices paid to Powerex and the credit and payment terms in the Transaction Confirmations between Powerex and CDWR, the California Parties have offered no other evidentiary support for their refund claims. Notwithstanding Mr. Hart's personal views on the subject, there is simply *no* probative evidence in the record that would support a finding that the prices paid by CDWR to PNW purchasers during the potential refund period were unjust and unreasonable. By contrast, TFG asserts, both it and its members, such as Powerex, have presented substantial record evidence in this proceeding, including expert testimony, fully justifying the market-based rates charged to CDWR. Thus the Presiding Judge must find that refunds to CDWR for its bilateral purchases from PNW sellers during the potential refund period are neither lawful nor appropriate under Section 206 of the FPA.

TFG avers that the potential refund period in Docket No. EL01-10 – December 25, 2000 through June 20, 2001 – can never become effective with respect to the California Parties' refund claims. Recognizing the limits on the scope of its authority to order refunds under Section 206, the Commission's July 25 Order specifically directed CDWR to file a complaint if it wished to seek refunds under its bilateral agreements.[87] CDWR has not done so.

CDWR's Deputy Director Mr. Hart stated that he personally favored refunds from Powerex, despite his previous pledge to Mr. Peterson in his capacity as the second highest-ranking official in CDWR that no such refunds would be sought. Exh. CAL-9 at 8; Exh. PWX-6 at 19. Mr. Hart went on to state that he was appearing only as a "fact witness" for the California Parties, and that CDWR's official position is that it is not seeking refunds for these PNW transactions. Tr. at 843:11-844:5. Mr. Hart further indicated that CDWR intends to do "nothing" about its long-term agreements that are now out of the money (*i.e.*, the contract price is higher than the now-prevailing market

---

[86] The $22.5 million three-day credit limit set by Powerex was sufficient to enable CDWR to purchase 45,000 MWh of power at the fixed $500 per MWh price, and was equivalent to a $225 million monthly credit limit. Tr. at 868:22-869:7; 870:21-25.

[87] 96 FERC at 61,515 n. 59.

price). Tr. at 948:11-12.

Thus, CDWR not only has filed no complaint at the Commission, but CDWR itself has failed to assert any refund claim whatsoever with respect to any of its transactions in the PNW or otherwise. In fact, CDWR has not even intervened in Docket No. EL01-10. Since CDWR is the real California party in interest in these transactions, but has chosen not to participate in Docket No. EL01-10, TFG believes that there is no claim for refunds to CDWR for the Commission to adjudicate, and that the California Parties' direct case is fatally flawed. Under AB-1X, none of the California Parties has the right to review CDWR's purchasing decisions. CDWR's contractual obligations are expressly not obligations of the State of California.[88] The CPUC has found that it has no authority to review the justness and reasonableness of CDWR's purchases. Exh. TFG-16 (CPUC Decision No. 01-03-082 at 14-15 (March 27, 2000)). CDWR, the party with the sole right under AB-1X to determine the justness and reasonableness of its power purchases, has not seen fit to seek refunds or revisit its own purchasing decisions.[89] Under these circumstances, the Commission should not sanction the California Parties' attempts to use Docket No. EL01-10 to accomplish what the California legislature has precluded them from pursuing in California.

If the California Parties are allowed to front CDWR's claims before this Commission, then the July 25 Order's directive that CDWR must file its own Section 206 complaint will have been effectively circumvented. The California Parties should not be allowed to seek a remedy indirectly (retroactive refunds) that the Commission has expressly denied to CDWR–both on the merits and procedurally.

According to TFG, the California Parties have premised their refund claims on generalized and unsupported conclusory statements by their witness Dr. Wolak that sellers exercised market power in California and the PNW. Exh. CAL-5 at 5-6. However, Dr. Wolak did not point to any specific instance where a specific seller exercised market power, nor did he relate his accusation to any particular transaction between CDWR and a counter-party. Similarly, Mr. Hart of CDWR could only make

---

[88] AB-1X, § 80200(d).

[89] CDWR's failure to intervene has also served to insulate it from discovery during the compressed procedural schedule in Docket No. EL01-10, further aggravating the due process problems discussed above. Should additional proceedings be ordered in this docket, CDWR must be made subject to full discovery, by all parties, regardless of its intervenor status.

bald and unsupported claims that CDWR had "no choice" in its purchasing decisions. Exh. CAL-9 at 2,3, and 6.

The Commission in its July 25 Order found the commingling of functions between CDWR and the ISO, to have conferred a competitive advantage on CDWR in negotiating bilateral contracts:

> . . . we note that while DWR is a market participant that competes with other suppliers and purchasers of energy and ancillary services in the ISO markets, unlike other market participants, DWR has had access to the ISO's control room and associated written materials, visual observations and oral statements regarding the ISO's markets, systems, operations and activities. *This has provided CDWR a competitive advantage in entering into bilateral contracts*.[90]

Based on this finding, TFG now alleges, in Docket No. EL00-95, the Commission determined that there was no equitable basis for granting refunds with respect to CDWR bilateral transactions. This equitable finding was in addition to the Commission's legal determination that "imposing after-the-fact refund liability on California transactions outside the centralized ISO and PX markets is unjustified."[91]

The record in Docket No. EL01-10 shows even more convincing and compelling proof that no equitable basis exists to justify potential refunds to CDWR in this proceeding, for it further documents the problematic relationship between CDWR/CERS and the ISO, which results in CDWR and CERS obtaining preferential access to the ISO's control room and to the ISO's transmission and market information, TFG argues. Even though Mr. Hart was the Director of CERS, he stated that he was unfamiliar with the Commission's standards of conduct for transmission providers, and did not know that they prohibited preferential access to transmission information. Tr. at 821:14-24. Mr. Hart admitted that CERS personnel had a continuing, 24-hour presence in the ISO control room. Tr. at 828:2-22. Mr. Green confirmed that he had met "maybe a half dozen" CDWR or CERS employees "that have transacted on the floor" of the ISO control room. Tr. at 832:15-20. With respect to CDWR's bilateral transactions with PNW sellers, Mr. Green admitted as follows:

---

[90] 96 FERC at 61,515 (emphasis added).

[91] *Id*.

A: Some of these were done in the day-ahead which was done back at the CERS headquarters, *but the vast majority of it was done real-time.*

Q: From the ISO?

A: From the ISO floor, yes.

Tr. at 831:25-832:4 (emphasis added).

TFG contends that there can be no doubt from these admissions by witnesses Hart and Green that CDWR and CERS had preferential access to the ISO's control room and to the ISO's transmission, operational and market information, in violation of the Commission's standard of conduct requirements. Such access clearly affected "the vast majority" of CDWR's PNW transactions, and without question, conferred a significant competitive advantage on CDWR . Thus, the record in this proceeding provides even more support for the Commission's finding in the July 25 Order that there is no equitable basis for awarding refunds to CDWR when it was competitively advantaged by its preferential access to market and transmission information.

TFG submits, that if the Presiding Judge finds, notwithstanding TFG's arguments to the contrary, that the California Parties' refund claims should be considered in Docket No. EL01-10, then safeguards should be instituted to prevent the California Parties from double-counting these transactions in Docket Nos. EL01-10 and EL00-95. This is necessary to ensure that the California Parties do not have a double-dip refund opportunity. Their claims, if even cognizable, are cognizable only in one proceeding. For purposes of *res judicata* and finality of the Commission decision-making process (not to mention transaction finality in WSCC bilateral markets), these transactions must be dealt with and disposed of in the California proceeding or the PNW proceeding—but not in both. These claims simply cannot be permitted to cruise the WSCC looking for a landing place.

Additionally, TFG argues that the California Parties' witness Mr. Green laid the predicate for segregation of their claims in his direct testimony and on cross-examination. Mr. Green testified that his testimony and exhibits segregated claims for transactions that should all be certified as part of the PNW for purposes of Docket No. EL01-10. Tr. at 886:23-887:4. He confirmed that anything involving the COB, NOB, Cascade and Summit delivery points was treated as a PNW transaction for purposes of his testimony and refund claims. Tr. at 887:17-21.

Thus the universe of CDWR bilateral transactions which the California Parties claim are subject to refunds in Docket No. EL01-10 is contained in Exhibit Nos. CAL-11 and CAL-12.[92] Mr. Green testified that these transactions he classified as part of the PNW constituted "something less than 50 percent" of CDWR's overall transactions. Tr. at 878:9-17. If the California Parties' refund claims with respect to the transactions identified in Mr. Green's testimony and workpapers are considered in this proceeding, then they should not be considered in any other proceeding, in order to avoid the potential for a double dip.

BONNEVILLE/BPA

Bonneville Power Administration ("Bonneville") avers that Part of the Commission's charge for this proceeding was to develop evidence regarding the definition of spot transactions in the PNW. 96 FERC at 61,520. The evidence developed through the hearing demonstrates that there is not a uniform or single understanding of what constitutes a spot transaction in the PNW. Rather than having a common definition, spot transactions have a temporal aspect that varies somewhat depending upon whether one is primarily a load serving entity or a marketer. While the evidence may have varied somewhat as to what a spot transaction is, it did not vary as to what is not a spot transaction. Despite the subtle differences between the manner in which a load serving entity and a marketer may view spot transactions, there are clearly some transactions that cannot be considered spot transactions. There is no credible evidence in the record to support the contention that transactions of one month or greater should be considered spot transactions. The refund claimants twist the definition of a spot transaction to the point that a contract of any length could be considered a spot transaction.

The generally inconsistent evidence presented by the Net Purchasers Group (NPG) and California Parties is designed primarily to increase their particular refund claim. Seattle testified that transactions eighteen months or less should be considered spot. Hearing Tr. at 576:22-25. The California Parties and Tacoma, on the other hand, testified that a contract of any length could be considered spot so long as the spot price influenced the contract prices (California Parties) or the transaction involved energy obtained on the spot market (Tacoma). Cal-5 at 4; NPG-46 at 16-17. Tacoma and

---

[92] *See* Exh. CAL-1 at 5-7 (describing CAL-2 and CAL-3); Exh. CAL-10 at 2 (describing CAL-11 and CAL-12, respectively, as revised and corrected versions of CAL-2 and CAL-3).

Northern Wasco's testimony on this point is at best ambiguous. Bonneville asserts that it is not clear whether they are arguing the definition of spot transactions should include these other types of transactions, or alternatively whether the Commission should expand the scope of transactions under consideration for refunds beyond just spot transactions. The central question to Mr. Movish was:

> Q: What transactions in the PNW *should be considered* in determining whether there may have been unjust and unreasonable charges for spot market sales?"
>
> A: The transactions that should be considered are (1) any and all purchases that are 24 hours or less and that are entered into the day of or day prior to delivery; (2) purchases that are either fully, or in part, comprise of energy obtained through spot market purchases; and (3) any purchases that are indexed to spot market prices.

NPG-46 at 16-17 (emphasis added). During his rebuttal testimony Mr. Movish expanded the scope to include any transaction affected by spot market prices. NPG-60 at 2-3. It is important to note that the question does not ask what a spot transactions is, but rather asks what transactions "should be considered" for refunds. This distinction is important because in his answer, Mr. Movish by implication acknowledges that the items 2 and 3 are not "spot transactions," but are transactions for which the Commission should consider for refunds.

Therefore, Bonneville maintains, rather than defining the scope of spot transactions, Mr. Movish is attempting to expand the scope of transactions eligible for refunds beyond spot market transactions. This is squarely at odds with the Commission's July 25th order. In the order the Commission specifically limited the scope of this proceeding to "facilitate the development of a factual record on whether there may have been unjust and unreasonable prices for *spot market bilateral sales in the Pacific Northwest…*" (emphasis added) 96 FERC at 61, 520. The Commission does not indicate anywhere in the order that this proceeding should be expanded to include anything other than spot market transactions.

Finally, according to Bonneville Tacoma and Northern Wasco also include transactions of any length that have prices tied to an index. NPG-46 at 17. The definitions propounded by those seeking refunds stretches the notion of a spot transaction beyond any standard understood in the industry, according to Bonneville. The temporal nature of a spot transaction no longer exists under these definitions. Under these definitions a transaction of any length could be considered a spot transaction so long as it has tangential relationship to the spot market. These definitions also do not comport with any identifiable class of products traded in markets in the PNW. These inconsistent and expansive definitions suggested by those seeking refunds highlights the rather self-serving nature of the proposed definitions. Rather than being based upon some industry notion of a readily identifiable product the definitions propounded depend in large measure on individual attempts by the group to fit particular contracts within the scope of transactions eligible for refunds in an attempt to maximize the size of the refund claim.

BPA and the TFG presented definitions of spot market transactions that conform to products traded in liquid markets in the PNW, Bonneville argues. While BPA and the TFG propose slightly different definitions, both are consistent with the industry understanding of the term. BPA's definition would include transactions for the balance of the month or less. BPA-1 at 5-6. The TFG limited the definition to transactions of 24 hours or less made within 24 hours of delivery, with certain exceptions for scheduling procedures. ENR-10 at 6. While these definitions are different, the differences merely highlight the difference between how load-serving entities like BPA and marketers view spot transactions in a slightly different fashion. BPA testified that the distinction between a spot transaction and a term transaction is based on the discretionary nature of the transaction. BPA-1 at 6-7. BPA generally plans its system on a monthly basis, and purchases within the month are viewed as spot transaction because of the limitations BPA has during the month to increase generation or reduce demand. *Id.* Paula Green of Seattle City Light acknowledged during cross examination that Seattle's real-time and next day traders handled balance of month transactions, while all other forward transactions were handled by a different set of traders. Hearing Tr. at 580. This testimony is consistent with the understanding that load serving entities view balance of month transactions in the same category as real time and next day spot transaction. The spot market traders at Seattle City Light deal with transactions that are balance of month or less. *Id.*

The TFG evidence highlights that entities primarily engaged in the business of trading energy view spot transactions on a slightly shorter time frame. This definition fits with the nature of the business, which is not engaged in serving loads but rather in buying and selling energy. The rebuttal testimony of Seabron Adamson contains a survey of traders in the PNW. ENR-25 at 3-4. Those traders surveyed by Mr. Adamson who worked for marketer side of the business viewed spot transactions consistent with the TGF definition. These traders, consistent with the nature of their business, view spot transactions as 24 hours or less. ENR-29. The survey also contained responses from two traders from NCPA, an entity with load serving obligations on behalf of its members. *Id*. The NCPA traders viewed the balance of the month transactions as spot transactions. *Id*. While both BPA and the TFG present credible evidence of industry definitions of spot market transactions, the NPG and the California Parties have attempted to fabricate definitions of spot market transaction in a effort to maximize their refund claim.

Many of the claimants are seeking refunds for transactions that are not PNW spot transactions, Bonneville contends. As demonstrated by the unrefuted evidence, refunds are being sought for transactions well beyond any reasonable definition a spot transaction, as well as transactions for load service in California. While it is not the charge of this proceeding to find individual refund liability, these claims demonstrate the futility of ordering refunds. Tacoma, Seattle, Northern Wasco and the California Parties are all seeking refunds for transactions longer than a month. Northern Wasco has stretched the definition to the point that they are seeking a refund for a three year indexed contract they have with BPA. BPA-1 at 8-10. While Seattle and Tacoma have a limited number of transactions, which fit under a reasonable definition of a spot market transaction, the majority of their claims involve transactions that are beyond the scope of this proceeding. PWX –1 at 24-25. The objective of these claims does not involve rectifying abnormalities on the spot market, but rather are attempts to unwind long-term transactions that those claimants now feel were too high.

CDWR/CERS has included in its claim against BPA exchanges with BPA and power sales that BPA sleeved for CRWR/CERS at their request. BPA-1 at 13-16. After the PX declared bankruptcy in January of 2001, BPA entered into several transactions to supply CDWR/CERS with power. BPA-1 at 13. Included among these transactions were exchanges.[93] *Id*. CDWR/CERS and BPA had no mutually negotiated nor agreed upon rates for these transactions. *Id*. at 15. CDWR/CERS took energy from BPA over peak demand hours to avoid extremely low reserve margins or blackouts, and supplied it back to BPA during light load hour periods, when CDWR/CERS could avoid system reliability issues. *Id*. BPA was flexible in working with CDWR/CERS on scheduling their returns to the extent possible to meet their system limitations. *Id*. CDWR/CERS representatives expressed that the return ratios they negotiated with BPA were more cost effective than using their own pumped storage generation alternatives. *Id*. at 15-16.

---

[93] "Exchanges" are transactions where one party delivers capacity and/or energy to another party, in exchange for a return of capacity and/or energy at a later time, sometimes 24 hours later, sometimes months later. This exchange of capacity and/or energy is in lieu of cash payments.

Since there was no dollar/MWh rate established for the exchange transactions, including them would require a separate examination of the "value" to each party as opposed to merely measuring a sales price against a Commission established just and reasonable market-clearing price. The Commission has made clear that the purpose of this proceeding is to develop a factual record regarding spot market bilateral *sales* in the Pacific Northwest. An exchange is not a sale, a distinction that is made clear in BPA's own organic statutes, which provides the BPA Administrator with express authorization to enter into exchanges, as distinct from power sales. *See*, 16 U.S.C. § 832d(b) (Bonneville Project Act).

Finally, Bonneville asserts, CDWR/CERS during March 2001, CDWR/CERS entered into several "sleeve" transactions with BPA under which BPA acted as an agent for CDWR/CERS to purchase the power on their behalf. BPA-1 at 13. "Sleeve" transactions are transactions where a third party (in this case BPA) acts as an intermediary between two other parties. The reasons BPA acted to sleeve some transactions to CDWR/CERS are: (1) CDWR/CERS asked BPA to do so when they were in a start-up mode and had not established themselves in the market; (2) California had been experiencing blackouts, which BPA considered to present a public health and safety issue, with potential to impact broader West Coast reliability; and (3) BPA received minimal compensation to conduct these transactions to cover its transmission expenses, losses, and other transactional costs. *Id*. CDWR/CERS noted in its rebuttal testimony that this description of the context for the sleeving by BPA is correct, and that BPA "offered us energy when no one else would." Cal-10 at 7.

This timeframe was marked by rapidly increasing wholesale electricity prices, volatility in the supply of electricity within California, and a perceived lack of creditworthiness of CDWR/CERS by many Pacific Northwest suppliers. *Id.* at 14. At CDWR/CERS's request, BPA acquired energy in the Pacific Northwest and then resold the same energy to CDWR/CERS. *Id*. This energy was desperately needed by California in order to maintain reliability margins. Obviously, BPA's willingness to step into the breach on behalf of CDWR/CERS or any other entity will be diminished, if not eliminated, if BPA is ordered by the Commission to refund some portion of the revenues used by BPA to pay for the power provided to CDWR/CERS.

STAFF:

According to Staff, much of the focus of this proceeding, both in the filed testimony and at the evidentiary hearing, was on the definition of "spot market" as it applied to the PNW. A key characteristic of each definition is the duration of the transactions encompassed by that term. Not unexpectedly, each interest group sponsored a different definition. More surprising than the different definitions sponsored by the groups, however, is the lack of consensus regarding the definition found within a group itself. The TFG, for example, argued that the spot market consisted of transactions of 24 hours or less, for immediate delivery, that were pre-scheduled no more than 24 hours in advance of delivery (with an exception for scheduling over weekends and holidays). *E.g.*, Ex. AE-1 at 14-15. PacifiCorp and Public Utility District No. 2 of Grant County, Washington (Grant County), [94] however, both of whom are members of the TFG, disagreed with this definition and contended that, in the PNW, the "spot market" included transactions of up to one month's duration (PacifiCorp) or transactions of up to one year's duration (Grant County). In a similar fashion, various members of the Net Purchasers Group and parties generally aligned with that group argued (in part) that the spot market (1) included transactions of up to eighteen months; (2) included transactions of up to two years duration and (3) included transactions under contracts of any duration, provided that the price was determined by reference to a spot market index. The position adopted by Commission Staff was that, under the acceptable business practices in the PNW, the spot market included "transactions which are for an hourly, daily, monthly basis and can be up to one year." Ex. S-1 at 17. In sum, there is no shortage of definitions; rather, the issue is selecting the one most strongly supported by the evidence and most appropriate for the region.

Staff submits, that a fundamental starting point in determining a definition of “spot market” in this proceeding is the Commission's orders. Although the Commission has recognized that the West is a single and "inextricably interrelated" market, it has also recognized that it is one characterized by important differences. [95] One such fundamental difference is that, while California administers its spot market sales through a centralized clearinghouse with a single auction price, the other Western states consummate spot market sales through individual bilateral contracts. [96] This essential difference, relied upon by the Commission when it established an evidentiary hearing in this case, was the basis for the Commission's observation that a "'spot market' sale for bilateral transactions in the Pacific Northwest may differ from what is a 'spot market' sale

[94] Grant County was represented jointly with Benton and Grays Harbor Counties. For convenience, we will refer to these public utility districts (PUDs), as “Grant County.”

[95] June 19 Order at 62,545.

[96] *Id.*

in the California ISO and PX organzied spot markets."[97] Commissioner Massey, in his separate dissent and concurrence, noted this statement with approval and went on to add that, in his opinion, a "spot sale in the Pacific Northwest could include sales up to a month's duration or even longer."[98]

Testimony from both the Net Purchasers Group and the TFG show that the PNW differs in many key aspects from the California market, Staff notes. There appears to be no disagreement among the parties, that, as noted by the Commission in its July 25 Order, the two regions have fundamentally different market structures, *i.e*., California has a centralized clearinghouse to administer spot market sales, while the PNW does not. Thus, rather than having a single trading point for all spot transactions, the PNW has multiple trading points and trades may take place at any point that the trading partners choose. [99]

The parties also agree, Staff maintains, that a second salient characteristic of the energy market in the PNW is the fact that its primary fuel is water. Unlike California, which has a preponderance of fossil fueled generation, the PNW obtains approximately 60 percent of its energy from hydropower. *E.g.,* Exs. NPG-4 at 24; S-1 at 8; AE-1 at 3; ENR-1 at 8. Mr. Robert McCullough, a witness for the Net Purchasers Group, testified that, "[f]or many years FERC has recognized that the PNW and other primarily hydroelectric systems operate very differently from thermal systems like those in California." Ex. NPG-1at 6. One consequence of this difference is that, since hydroelectric projects are incapable of running constantly, Northwest utilities make purchases from thermal units "on an hourly, daily, weekly or monthly basis" to fill in when their hydroelectric project are incapable of serving load. *Id.* at 7.

Staff states that Mr. Samuel Van Vactor, a principal witness for the TFG, characterized the PNW Market as "radically different" from that of California. Ex. ENR-1 at 3. He offered detailed testimony concerning the differences between the PNW and

---

[97]July 25 Order at 61,520 and note 74.

[98]*Id.* at 61,522.

[99]These trading points include the California-Oregon border (COB), the Nevada-Oregon border (NOB), Palo Verde and Mid-Columbia. At the very least, a "modest price differential" exists among these points. Ex. NPG-74 at 7; Ex. PWX-1 at 20; Ex. BPA-1 at 6.

the California Markets. To quote Mr. Van Vactor's summary concerning these differences (*id.* at 9):

> The Pacific Northwest market has been in operation for over twenty years and has not undergone a radical restructuring; there are no substantial 'stranded costs' in the region; the major trading entity in the region is a federal agency; the region is dominated by hydroelectricity generation and relies less on spot trading; the transmission infrastructure in the major population areas is relatively uncongested; demand is more price sensitive than in California; utilities were free to choose how and when to trade [and] there was no mandate to trade in a centralized market or exchange . . . .[[100]]

Mr. Van Vactor explained that the Northwest's limited ability to store water (the region's reservoirs can store approximately three months worth) allows it "some flexibility in the use of thermal resources." *Id.* at 11. A resulting characteristic of the region's markets, according to Mr. Van Vactor, is that it has "a greater number of forward contracts" than does California. *Id.*

Additionally, Staff contends, as noted in the Commission's July 25 Order (FERC at 61,520), and established by the evidence here, energy transactions in the PNW occur as a result of bilateral contracts negotiated by the parties thereto. Because the PNW has no mandatory clearinghouse comparable to the CAISO, there is no single uniform set of terms and conditions that apply to all power transactions. Ex. NPG-74 at 6. Instead, wholesale power in the Northwest is bought and sold under circumstances specific to each buyer and seller. *Id*. Mr. Robert McCullough testified that in the PNW "[r]elatively few transactions take place on an hourly basis" due to the operating realities of the electric system, *i.e.*, "[f]ew control areas can wait until the hour of operation to arrange

---

[100]Mr Van Vactor completed his summary by noting that "utilities in the region were forewarned about the risk of depending on the spot market to meet firm load." The Net Purchasers Group, however, generally maintained that its members had taken all appropriate measures to lessen their dependence on the spot market. *E.g.*, Ex. NPG-4 at 18-21.

for supply." Ex. NPG-1 at 9. (Mr Adamson, for the TFG, agreed that the PNW has a relatively small real-time market. Ex. ENR-10 at 8.) Thus, the majority of the "players" purchase power on a forward basis, usually on a daily, weekly or monthly basis. Ex. NPG-74 at 9.

Staff submits that the evidence establishes that the majority of the bilateral contracts in the PNW are either schedules under the Western Systems Power Pool Agreement (WSPP) or contracts with the Bonneville Power Administration (BPA). [101] Exs. S-1 at 8; NPG-4 at 13; NPG-74 at 6; GT-1 at 13; ENR-1 at 3. The WSPP Agreement is an "umbrella agreement" that establishes standarized terms for discretionary power transactions among WSPP members. Ex. NPG-74 at 4; NPG-4 at 13. Typically, potential counterparties in a WSPP agreement use oral or written confirmations to establish the terms of a particular sale transaction, such as its volume, price and duration; there may be several confirmations during the term of the contract. [102] NPG-74 at 6. The WSPP Agreement does not define spot market. [103] Ex. S-1 at 12. BPA's website, although similarly failing to define spot market, does state that a spot market price "often" occurs as a result of an hourly or weekly transaction. Ex. S-1 at 13.

According to Staff, the evidence shows that many of the market participants in the PNW fall into one of two categories: they are either power marketers or Load Serving Entities (LSEs). These two groups are characterized by important differences. LSEs, for example, "typically" own their own generation resources, which they use to serve their load obligations, i.e., retail customers, end users and wholesale requirements customers. Ex. AE-1 at 5. Because the production of hydroelectricity depends on water

[101]A preliminary examination of the data submitted to the Presiding Judge and to Staff on August 16, 2001, however, indicates that a significant number of contracts do not fall under either category. There are other types of bilateral arrangements and contracts under FERC tariffs. Ex. S-3 at 7.

[102]As one witness explained, the WSPP "agreement provides for some standards, but the specifics of any single deal, be it a day-ahead, real-time, or quarterly transactions, are contained in the confirmation that goes along with the deal." Ex. GT-1 at 6.

[103]It does state that all transactions under the Agreement and Confirmation Agreements "are forward contracts, *as those terms are used in the United States Bankruptcy Code.*" Ex. S-1 at 12 (quoting § 35 of the WSPP agreement; emphasis added). The clear wording of the Agreement, in Staff's view, limits its characterization of these arrangements as "forward contracts" to their use in bankruptcy proceedings.

levels, an LSE's native generating facilities will sometimes be more than enough to serve its load obligations and will sometime be less. *Id.* When it is less, the LSE generally obtains needed supply through contracts with third parties; when it is more, the LSE typically sells the surplus to others. *Id*. Unlike an energy marketer, an LSE has a legal obligation to provide service, regardless of the level of demand and of the cost of the energy; they are not free to abandon native load. Ex. NPG-4 at 16. Accordingly, a Northwest LSE must purchase several days to many months in advance. [104] *Id.* at 17.

A marketer, unlike an LSE, does not own generation, but buys and sells electricity from a portfolio of assets. Ex. AE-1 at 13-14. These portfolios contain power products, or contracts, with differing terms, degrees of risk, delivery points and prices. Marketers typically purchase rights to energy and capacity from sellers, which, in turn, they offer to buyers on a continuous basis. *Id.* Marketers have no obligation to serve load and no continuing obligation to the parties who use their services.

Staff avers, that the parties in this case, as previously noted, offer several definitions of spot market transactions. Staff discusses the main evidentiary underpinnings of these differing definitions below.

According to Staff, Mr. Stephen Oliver testified on behalf of BPA, which owns and operates approximately 80% of the PNW's high-voltage transmission systems and markets 40% of the electricity consumed in the region. Ex. BPA-1 at 3. It is thus a dominant presence in the region's power markets. Exs. ENR-1 at 10; BPA-1 at 3. Mr. Oliver explained that the Northwest and California markets were "structurally different." Unlike California, which has a single trading point for all spot transactions, the PNW has a number of points of interconnection at which transactions occur on a bilateral basis. In addition, Mr. Oliver pointed out that "the time period of the transactions" in the Northwest "is not as structured as in the ISO and PX." *Id.* at 6. Based on these structural differences, Mr. Oliver testified (*id.* at 5) that

> Pacific Northwest spot market bilateral sales should be limited to real-time sales (within the same day, next hour), prescheduled sales (for the following 24-hour period), and within month and balance of the month

[104]The record contains abundant evidence that prudent utility practice, as well as FERC policy, discourages over-reliance upon spot purchases. Exs. NPG-74 at 5; PacifiCorp-1 at 5; PWX-1 at 21.

> sales (those sales that occur after the first of any month, for some short duration within the month, or for the remainder of the month) executed during the period December 25, 2000 through June 20, 2001, with delivery points inside the Pacific Northwest, including deliveries at the California-Oregon and Nevada-Oregon borders (COB and NOB) to serve loads within the Pacific Northwest. [[105]]

Observing that spot transactions "by their nature" are purchased to balance the short-term needs of the underlying loads, Mr. Oliver explained that within the month and balance of the month transactions were appropriately included in his definition because they were "usually made because of unanticipated changes in loads or generation after the month begins" and (like spot sales) were typically not discretionary. *Id.* at 6.

Mr. Stan Watters, an officer of PacifiCorp whose responsibilities included the oversight of his company's wholesale sales and trading functions, offered significant testimony on the spot market issue. Ex. PacifiCorp-1. PacifiCorp, as explained previously, is a member of the TFG and generally "supports and adopts as its own the testimony sponsored by" the Group's witnesses; in particular, it agrees with the Group's "central position" that ordering refunds among the PNW Parties is "wholly inappropriate." *Id.* at 2. Nevertheless, Mr. Watters appeared to rebut the Group's testimony that spot market was limited to 24 hours or less. *Id.* Mr. Watters' testimony is particularly instructive because it explains the business practices of LSEs in the PNW and why a "24 hour or less" spot market definition is inappropriate for that region.

Consistent with testimony offered by the Net Purchaser Group (*e.g.*, Ex. NPG-4 at 17), Mr. Watters stated that LSEs attempt, to the "maximum extent practicable," to avoid exposure to "the high volatility of the near-term market." *Id.* at 3. Because long-term planning decisions are "inevitably imperfect," however, LSEs are forced to engage in "a process of buying and selling power in transactions up to one month in duration" in order "to triangulate toward a precise balance of loads and resources when the hour of actual delivery occurs." *Id.* These one month purchases frequently require an LSE to engage in near-term sales. As Mr. Watters explained, LSEs frequently buy "standard products"

[105]Mr. Oliver excluded bilateral transaction to serve load outside the Northwest from his definition because he considered such an exclusion a "practical" way to prevent overlap with the California complaint proceeding. Ex. BPA-1 at 7.

offered by the industry to meet demand during their heavy load hour because doing so minimizes their exposure to the unpredictable hourly market. Despite the fact that it is the most-economical and lowest-risk means for meeting peak load demands, however, a standard product may deliver more power than the LSE needs. For this reason, and because expected load sometimes fails to materialize, an LSE is forced to sell the surplus energy into the "near-term market." *Id.* at 3-4. As Mr. Watters went on to explain, transactions up to one month in duration, as well as one-hour purchases or sales made on a particular day were equally "integral to the load balancing function of load-serving entities and . . . substantially affected by whatever imperfections might have existed in near-term markets;" he knew of "no principled basis for distinguishing" between the two. *Id.* at 4-5. Mr. Watters testified that a "24 hour definition" penalized prudent utilities that had followed "Commission policy and prudent utility practice" by reducing their exposure to the volatile hourly and daily market. He further testified that defining "spot" to include monthly transactions not only avoids this "inequitable and perverse" outcome but also establishes "a defensible boundary between [an LSE's] 'planning' function and [its] near-term load balancing function." *Id.* at 5.

Ms. Natalie Tingle-Stewart, an expert analyst with the Commission's Trial Staff, testified that her "preliminary conclusion," based on the transactions that she had been able to examine in the limited time available, was that spot transactions in the PNW "should be transactions which are for an hourly, daily, monthly basis and can be up to one year." Ex. S-1 at 17. She based her conclusion, she explained, on business practices in the PNW and the "peculiarities" of the market in that region. *Id.* at 17; Tr. 1240. At the hearing, Ms. Tingle-Stewart testified that she had considered the fact that many localities "typically" defined "spot" as transactions of 24 hours or less, as well as the distinction between spot and forward transactions. Tr. 1240. In view of the differences in the Northwest markets, however, these factors had not affected her preliminary conclusion.

Tr. 1240-41.

Ms. Tingle-Stewart explained that she had researched the definition of spot market used by several entities that were either councils or regulatory agencies operating in the PNW or that traded with, or were bordered by, the Northwest's energy market. Ex. S-1 at 12. Her examination indicated that there was no consensus regarding the definition. *Id.* at 11-15. Ms. Tingle-Stewart also reviewed and considered the various spot market definitions found in the testimony and exhibits filed by EWEB, SMUD, the Net Purchasers Group and the California Parties. On cross examination, Ms. Tingle-Stewart stated that, after filing her written testimony, she had also reviewed responsive testimony filed by the TFG. [106] She testified, however, that her review of the TFG's evidence had not affected her preliminary conclusion, *i.e.*, that spot transactions could be up to one year's duration. Tr. 1241.

Several witnesses from the Net Purchaser Group and the California parties testified, among other things, regarding an appropriate "spot" definition. These include Ms. Paula Green (an employee of Seattle City Light), Mr. Robert McCullough (a consultant), Mr. Scott Spettle (an employee of EWEB) and Mr. Philip Movish (a consultant).

Ms. Paula Green testified that for LSEs “the standard practice for spot market transactions outside of California includes monthly forward purchases and sales." Ex. TFG-4 at 18. Pointing to significant price increases in the spot market, beginning in May 2000 and a deteriorating water supply that affected the availability of hydropower, Ms. Green testified that Seattle City Light "decided it would be prudent to make significant forward purchases in the monthly spot market to serve load." *Id*. at 12-15. In Ms. Green's opinion, the PNW's spot market included "any transaction up to 18 months in duration." *Id.* at 23. She based her opinion on the fact that the City of Seattle had delegated authority to the utility to enter into short-term spotmarket agreements for storage, sales and purchases. [107] Ms. Green further testified that she would limit spot market transactions to 18 months because anything longer was "inconsistent with the operation of the hydroelectric system in the Northwest." *Id.* at 24.

Mr. Robert McCullough testified that, in the PNW, all "purchases and sales of less than one year duration" are regarded as "spot purchases." Ex. NPG-1 at 12. Consistent with Mr. Watters' testimony regarding the region's use of "standard products" to supply buyers' needs, Mr. McCullough testified that sellers package hourly supplies into "daily,

---

[106]These exhibits and testimony, which were filed by the group on the same date as Staff filed its responsive case, had been unavailable to Ms. Tingle-Stewart when she prepared her written testimony.

[107]Ms. Green explained that the 18 month period was based on "standard practices" associated with the Pacific Northwest Coordination Agreement, which was established in 1962 by all the major utilities operating control areas in the Northwest. Ex. NPG-4 at 23. The Coordination Agreement establishes monthly obligations for the signatory parties based on a "water year." The City of Seattle recognized that spot transactions "would be related to the Coordinated system plan and regulation" and could extend beyond a current fiscal year; hence, the 18 month delegation. *Id.* at 24.

weekly, or monthly blocks" because these packages are more efficient for both buyers and sellers than "new negotiation[s] for every hour." *Id*. at 9. As a consequence, spot purchases in the PNW "tend to reflect the longer operational needs of the ultimate consumers." *Id.*

Like Ms. Green and Mr. McCullough, Mr. Scott Spettel, the witness for EWEB, testified that spot transactions were considerably longer than 24 hours. Ex. NPG-74. Mr. Spettel stated that wholesale power in the region was commonly "bought and sold for terms ranging from next-hour, next day, balance of month, monthly, and quarterly through a term of twelve months." *Id.* at 6. Mr. Spettel testified that, in his opinion, each of these transactions was part of the "spot market." *Id.* at 7. Noting that transactions of a month or longer are frequently referred to as "term" or "mid-term", Mr. Spettel stated that "the pricing of these transaction is related to the price volatility observed or expected in the next-hour and next-day markets." *Id.* Mr. Tim Culbertson, the witness for Grant County,[108] agreed "for the most part" with Mr. Spettel's testimony. Ex. GT-1 at 6. Mr. Culbertson testified that an appropriate definition of spot market should include transactions that were longer than real-time and day-ahead because "monthly, quarterly, and even transactions up to a year involve a standardized product, can be consummated just as fast as a day-ahead or real-time deal, and trade at prices that are, for the most part, transparent." *Id.*

Mr. Philip Movish, a witness for the City of Tacoma, Port of Seattle and Northern Wasco, testified that spot transactions included (1) all transactions of 24 hours or less, entered into the day of, or day prior to delivery; (2) purchases that partially or entirely comprised "energy obtained through spot market purchases;" and (3) "any purchases that are indexed to spot market prices," regardless of the duration of the underlying contract. Ex. NPG-33 at 17. He acknowledged that, for California, the Commission had defined spot sales "as sales that are 24 hours or less and that are entered into the day of or the day prior to delivery." *Id.* at 16. He stated, however, that the definition should be adjusted to account for the differences in the Northwest market. *Id.*

Dr. Frank Wolak testified for the California Parties. Noting that Northwest LSEs generally turned to the market only when their own generation resources were insufficient to serve load, he testified that their need "for additional energy is rarely for a single hour or for a single day;" their needs, rather rather, extend over "hours, days or

---

[108]Grant County and its associated PUDs, although members of the TFG, did not agree with that Group’s definition of spot market.

even months." Ex. Cal-5 at 4. Dr. Wolak stated that the LSEs' "need for additional energy is typically for a significant period of time because the Pacific Northwest is a hydro-based system." *Id.* He explained that, because water conditions usually last for an entire year, and the impact of a low water year is felt the following year, LSEs must replenish their reservoirs over a long period of time. Based on this factor, as well as his analysis of a generator's potential exercise of market power, he concluded that "bilateral sale[s] of electricity in the Pacific Northwest market should be subject to refund . . . as long as two years in advance of the delivery date. *Id.* at 5.

The TFG (except for PacifiCorp and Grant County) argues that spot transactions in the PNW are "sales with a duration of 24 hours or less," entered into the day of, or the day before delivery, except when the latter occurs on or after a weekend, holiday or WSCC scheduler conference." Tr. 1110-11; *e.g.*, Ex. ENR-10 at 8. TFG's principal witnesses on this issue were Samuel Van Vactor (Ex. ENR-1); Seabron Adamson (Ex. ENR-10); Dr. Richard Tabors (Ex. PWX-1) and Mr. Christopher Stelzer (Ex. AE-1). These witnesses prepared their testimony in conjunction with each other and with Mr. Scott Jones (Ex. PPL-1); the five testified as a panel at the hearing. Ex. PPL-1 at 2; Tr. 1061. Mr. Stelzer is employed as an energy trader for Avista Energy, Inc. (a member of the TFG), while Dr. Tabors and Messrs. Van Vactor, Adamson and Jones are consultants retained as witnesses by various members of the TFG. Exs. AE-1 at 1; ENR-1 at 1; ENR-10 at 2; PWX-1 at 2; PPL-1 at 1.

Mr Adamson testified that a "standard economic definition" of spot market was limited to "transactions for immediate delivery, at prevailing prices." ENR-10 at 6. He modified this definition, however, to that quoted above, to be "consistent with actual trading practice" in the PNW. *Id.* at 8-9. Mr. Adamson explained that his modified definition was "appropriate" because it "capture[d] the immediate nature of spot transactions;" it "recognize[d] the realities of the Pacific Northwest market" and it could be consistently applied. *Id.* at 8.

Although acknowledging that "immediacy" was a component of the economic definition of spot transactions, Mr. Adamson explained that it was necessary to "balance strict economic interpretations" with market realities. *Id.* at 9. His definition allowed an exception to immediate delivery for scheduling conventions, he explained, because limiting the term to "transactions . . . strictly made within 24 hours of delivery would not be consistent with actual trading practice." *Id*. at 8-9. He had also extended the "standard" definition to include transactions that were extended beyond "real time" because "the market d[id] not operate that way." *Id.* at 9.

At hearing, Mr. Adamson clarified that his "judgment about the appropriate definition of the spot market really had two components, an economic one and a practical one." Tr. 1112. With respect to the latter, he relied upon a telephone survey of four energy traders, as well as "a kind of e-mail survey" of twenty-six respondents. On cross examination, Mr. Adamson testified that he had not included individuals from BPA or PacifiCorp (the two largest participants in the market) in his survey. *Id.* He also conceded that the twenty-six respondents in his e-mail survey were employed by members of the TFG and that one, Mr. Christopher Stelzer, was a fellow panelist. Tr. 1144-49.

Dr. Tabors largely agreed with Mr. Adamson. He believed that the Net Purchasers Group was trying to obtain refunds for “forward,” rather than “spot,” transactions. Ex. PWX-1 at 21-22.

Mr. Van Vactor defined "spot" transactions as those made "for immediate delivery of the product," with "[t]ypically" no ongoing commitment between buyer and seller. Ex. ENR-1 at 8. He stated that electricity "is different from other commodities in that a physical transfer does not take place in the usual fashion;" according to Mr. Van Vactor, the significant factor for determining spot transactions for electricity was the scheduling of generating units for dispatch. *Id.* On cross examination, he testified that his definition of spot markets and those of his fellow panelists, were "based on our experience" in markets and regions other than the Pacific Northwest." Tr. 1116.

The last panelist, and the only one with actual experience in trading energy, was Mr. Christopher Stelzer, a trader employed by Avista Energy, a marketing and trading company that does not own any generating assets. Ex. AE-1 at 2. Stating that he agreed with Mr. Adamson's definition of spot market, Mr. Stelzer testified that the definition was consistent with his experience as an energy trader. *Id.* at 14. At the hearing, Mr. Stelzer answered a number of questions on cross examination regarding "standard products," which Mr. Stelzer defined as the "products that are most commonly traded in the market and don't need further changes in terms of normal WSPP agreement." Tr. 1127-28. One such "standard product" is a "6 X 16 peak product," designed for heavy load periods, which delivers energy six days a week (Monday through Saturday) for sixteen hours a day (6 a.m. to 10 p.m.). Tr. 1130. Mr. Stelzer testified that LSEs had "a need to deal in things other than standard products in order to cause loads and resources to balance." Tr. 1137-38. Marketers by contrast are able to meet their obligations simply by purchasing standard products. *Id.*

Staff maintains, that Mr. Van Vactor's testimony also raised doubt about the degree to which the advocates of a 24-hour definition based their opinions on the actual conditions prevalent in the PNW market. He stated that his opinions and those of his fellow panelists were based on their experience in markets other than the PNW. Tr. 1116. Given the Commission's express recognition that the PNW spot market may not be identical to that in California, this statement undermines the value of Mr. Van Vactor's testimony, as well as that of his fellow panel members.

In summary, it is Staff's position that the spot market in the PNW region should be defined to include transactions that are greater than 24 hours. This reflects much more accurately the nature of the PNW market, where LSEs must balance short-term purchases, which include not only 24-hour purchases but also ones of longer duration, often for a week or balance of the month, to meet power needs not satisfied by their largely hydro generation capabilities. In contrast, the witnesses advocating a 24-hour definition, such as Mr. Adamson, expressly recognized that a "standard definition" must be modified to fit the business realities of the PNW. Yet these witnesses went on to base their views more on an academic, definition-driven generalized notion of what a spot market should be than on actual conditions and business practice in the PNW market. For this reason, their testimony is less probative.

Just as Staff does not agree with the TFG's "24 hour or less" position,[109] however, it also takes issue with the contention of the Net Purchasers that "spot" transaction necessarily include all those transaction that range up to 18 to 24 months or "any purchases that are indexed to sport market prices," regardless of the duration of the underlying contract. Exs. NPG-33 at 17; NPG-1 at 9; NPG-4 at 23. Although Staff found the TFG's evidence concerning the appropriate "spot" definition less than compelling, it agrees with TFG's contention that any useful definition of "spot" must be geared towards some sense of immediacy, as understood in the market of a particular region. *See* Ex. ENR-10 at 8. Staff also agrees with both BPA and Pacificorp that decisions made as part of an entity's "planning function do not properly belong in a proceeding that is limited to spot market transactions." Exs. BPA-1 at 6; PacifiCorp-1 at

Based on Staff's preliminary examination of the massive data submissions in this case, it concluded that the spot transactions could range up to one year. Should the Commission decide to continue this proceeding for a determination of individual refund

[109]We are using this term as a short hand reference to the definition of "spot market" sponsored by the TFG. *See, e.g.*, Ex. ENR-10 at 8.

claims, a more precise definition would be needed. Based on the entire evidence in this proceeding, including the hearing, Staff now believes that the most appropriate limitation for spot market sales in the PNW is one month. Staff, however, is also of the opinion that parties should be permitted to show specifically, for transactions longer than one month but not more than one year, that particular contracts were not part of long term planning and thus should be considered spot transactions. Defining spot market as including transactions that extend up to one month is consistent (as explained previously) with the realities of the market in the PNW and includes transactions that "are of short enough duration that there are usually no other reasonable alternatives than to purchase from the market, or sometimes to sell, as in the case of non-discretionary generation production, such as may occur with hydroelectric systems." Ex. BPA- 1 at 6-7. Limiting spot transactions to one month also serves to exclude transactions that are part of an entity's "planning" function; we agree with PacifiCorp and BPA that these transactions do not belong in a proceeding limited to spot sales. *See* Ex. PacifiCorp-1 at 3; Ex. BPA-1 at 6.

Staff also noted, that although the record in this proceeding did not establish that any one entity exercised market power, there is evidence that, if further investigated, may establish that market power was exercised, Staff states. Staff asserts that if it is established that a party exercising market power also sold under long term contracts with prices indexed to the spot market, such transactions (although not spot sales) should also be subject to refund.

The Presiding Judge's August 23 Order On Issues stated that the spot market issue pertained to "the Pacific Northwest as defined in the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 893a(14)" (Conservation Act). This statement incorporated the stipulation of the parties regarding this issue.

In examining the evidence regarding spot market, Staff noticed that, notwithstanding the parties' stipulation, certain witnesses maintained that the geographic definition of PNW found in the Conservation Act was, or was not, appropriate for use here. [110] If the Commission determines that further proceedings are warranted, it is Staff's view that it should decide (1) whether the geographical definition of PNW is settled by the stipulation; and (2) if not, whether the Conservation Act's geographic definition should be used in any refund proceeding.

---

[110]*See, e.g.* Exs. ENR-1 at 2-7; Ex. NPG-12 at 2-6; PWX-7a at 5.

RECOMMENDATIONS:

I agree with Staff that the Commission has recognized that the California and PNW power markets, while "inextricably interrelated," also differ in important ways. In particular, California has a centralized spot market with a single auction price, while the PNW spot market operates through individually negotiated, bilateral contracts. California also relies far less on hydropower than does the Northwest. These fundamental differences support a the conclusion that the spot markets in the two regions may be defined in a different manner. This comports with the Commission's determination that, while the Western Region is one market, it is a market characterized by significant differences.[111] In view of the Commission's statement in this case, that the spot market in the Northwest may differ from that in California, I believe that the most probative evidence is evidence that focuses most directly on the differences between the two regions and how (if at all) those differences bear on the operation of each region's spot market.

I further agree with Staff that the manner in which LSEs in the PNW market purchase power indicates that spot market purchases are considerably more variable in duration than in the California market and thus cannot practically be encompassed by a 24-hour limitation. Due to the fact that electric generation is primarily dependent on water in the PNW, as opposed to fossil fuels as in California (*e.g.*, Ex. ENR-1 at 8), the energy supply is subject to greater variation due to changes in natural conditions. Ex. AE-1 at 5. Water conditions usually last for a year, and the impact of a low water year is felt the following year. Thus, when the LSEs need energy, it is rarely for a single day, but instead for significant periods of time. Ex. Cal-5 at 4.

Furthermore, the LSEs have a legal obligation to provide service, regardless of the level of demand. Ex. NPG-4 at 16. They therefore cannot afford to "wait until the hour of operation to arrange for supply." Ex. NPG-1 at 9. They instead must purchase days or months in advance. Ex. NPG-4 at 17. As Mr. Watters explained, to avoid the volatility of the near-term market, LSEs engage in a process of buying power in transactions up to one month in duration in order to "triangulate toward a precise balance of loads and resources when the hour of actual delivery occurs." Ex. PacifiCorp at 3. Within-month and balance-of-month transactions are undertaken for the same purpose as 24-hour transactions--the need to make up for unanticipated changes in loads or resources--and, like the shorter transactions, the longer ones are not discretionary. Ex. BPA-1 at 6.

---

[111] June 19 Order at 62,545.

Transactions of various lengths are thus part of the same cohesive process; as testified by Messrs. Watters and Oliver, these transactions are properly part of the PNW spot market. To separate those transactions into categories, such as “more than 24 hours” and “less than 24 hours,” would be to ignore arbitrarily the purpose for which the transactions are carried out. As Mr. Watters stated, there is “no principled basis for distinguishing” between the two. Ex. PacifiCorp at 4-5.

Other testimony showed that actual practices in the PNW compel the conclusion that the spot market there is considerably broader than 24-hour transactions. I agree with Bonneville that the the testimony favoring a 24-hour definition, by contrast, reflects more the practices of the marketers in the region or those who are not LSEs. Mr. Adamson, for example, based his opinion in part on an e-mail survey of 26 respondents, who mostly represented the views of marketers rather than LSEs. Two respondents which were LSEs supported Bonneville's definition. As explained above, marketers are impacted less by the realities of the PNW market than are LSEs. The former do not own generation and are under no legal obligation to provide power to anybody. Ex. AE-1 at 13-14. They therefore do not operate under the same need to integrate longer and shorter term purchases so as to balance their supply and demand.

In this regard, I find Bonneville's testimony persuasive and the preponderance of the evidence makes me recommended that Bonneville's definiton for spot markets be adopted. To wit, real-time, prescheduled, and within the month and balance of the month transactions during the relevant time period at issue in this proceeding. I find persuasive that within the month or balance of the month transactions, to balance loads, should be included in the definition of spot markets in the Pacific Northwest. Moreover, I agree with Staff as explained in its brief and TFG that longer transactions including transactions indexed to spot market prices, should not be included in the definition. I agree that the definition should include some sense of immediacy, as understood in the market of a particular region. In so doing I am aware that the Commission in previous decisions encompassing the area at issue in this proceeding, has referred to spot market transactions as ".... means sales that are 24 hours or less and that are entered into the day of or day prior to delivery." See June 19 order. I believe within month and balance of month transactions, to balance load, based on the evidence in this case is an appropriate definition for spot market sales in the Pacific Northwest.

I agree with Bonneville that both exchanges and sleeve transactions should not be part of this proceeding and therefore, so recommend. These transactions are not spot market transaction within the meaning of the definition.

I believe the record supports the definition of Pacific Northwest used at the hearing as stipulated to by the parties or as defined in the Pacific Northwest Electric Power Planning and Conservation Act ("Conservation Act"). I agree with TFG that the definition informs and guides the conduct of market participants. Moreover, this is the definition used by Puget in its complaint. The definition matches the operational characteristics of the power systems and waterways and conforms to the existing political organization of the region. The parties arguing for a different definiton in the post-hearing briefs have not given compelling reasons for me to reach a different conclusion. I find significant Mr. Van Vector's testimony that all refund proponents except for California, are within the Conservation Act territory, and thus, adopting a broader definition, would expand the investigation of this preliminary hearing. It also bears noting that the Commission, when it has deemed it appropriate has used the WSCC as the geographical boundary. *See e.g.* June 19 Order at n.4. I recommend adoption of the definition of the Conservation Act.

Additionally, I find that Staff's asssertion that there is evidence that if further investigated may establish that market power was exercised is of very little probative value. Staff did not submit any testimony on the issue of market power. Moreover, in light of the record developed in this proceeding, I recommend that this statement not be given any weight. Furthermore, as discussed under issued number two below, the evidence developed in this case, does not support Staff's speculation. The discussion below, further supports this recommendation.

Although I allowed the California Parties to participate in this proceeding, in light of the record developed in this case, I recommend that the claims dealing with CDWR/CERS bilateral transactions, not be considered in this record. The transactions do not involve transactions into the Pacific Northwest and Puget's complaint specifically referred to transactions into the Pacific Northwest. To wit, the complaint requested an order "capping the prices at which sellers subject to Commission jurisdiction, including sellers of energy or capacity under the Western System Power Pool Agreement ("WSPP Agreement"), may sell capacity or energy into the Pacific Northwest wholesale power markets." Therefore, EL01-10 does not include bilateral transactions involving CDWR since the transactions were sales into California. Moreover, the Commission declined to order refunds with respect to these same agreements in the California refunds proceeding or Docket EL00-95.

The claims by the California Parties were fully addressed in the July 25 Order, in Docket EL00-95. It bears noting that in the July 25 order the Commission stated:

> We believe imposing after-the-fact refund liability on California transactions outside of the centralized ISO and PX markets is unjustified. This is particularly true in the instant proceeding when the Commission consistently encouraged California load serving entities to acquire a balanced portfolio of short, medium and long-term contracts. Expanding the scope of transactions subject to refund over the period October 2, 2000, through June 20, 2001 to include transactions outside the ISO and PX centralized markets would simply hinder the ability of parties to enter into new bilateral contracts...... In addition, by voluntarily entering into bilateral transactions outside the ISO and PX, DWR made a conscious decision to forego the refund protection that the Commission provided for purchases through the ISO and PX. Thus, there is no equitable rationale that supports making DWR's bilateral contracts subject to refund.

July 25 Order, *slip op.* at 32-33.

The Commission's previous decision concerning the CDWR claims is applicable to this case. I agree with TFG that the correct construction of EL01-10, is to exclude CDWR bilateral transactions and is limited to transactions within the scope of Puget's complaint.[112]

2. May unjust and unreasonable prices have been charged for spot market bilateral sales in the Pacific Northwest for the period December 25, 2000 through June 20, 2001?

NPG:

---

[112] If the Commission finds that the claims should be considered, the other issues alleged by TFG, (that the transactions involved are not spot market, standing, access to ISO), Duke Energy (the California parties failed to meet their burden of proof because their underlying data is erroneous) must be considered. I agree with Staff the Section 35 of the WSPP Agreement states that all transactions under the Agreement and confirmation agreements are "forward contracts, as those terms are used in the United States Bankruptcy Code." Exh. S-1 at 12. This limits the characterization of forward contracts to their use in bankruptcy proceedings.

The Attorney General of Washington filed a brief in support of refunds arguing that refunds are in the public interest because the rates were unjust and unreasonable.

NPG avers that in its July 25 Order, the Commission states that this "preliminary evidentiary proceeding" is "intended to facilitate development of a factual record on “whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest."[113] The August 23, 2001 “Order on Issues” lists whether or not unjust and unreasonable prices “may” have been charged for Pacific Northwest spot market sales during the period December 25, 2000 through June 20, 2001, as an issue in this proceeding. NPG maintains that the Commission has already determined that unjust and unreasonable prices were charged for Pacific Northwest spot market sales during the refund period. Moreover, despite the truncated nature of this preliminary evidentiary hearing, the record compiled in this proceeding confirms the Commission’s finding that Pacific Northwest spot market prices during the refund period were unjust and unreasonable.

Section 206 of the Federal Power Act (“FPA”) empowers the Commission, “upon a complaint” or “its own motion,” to institute an investigation into whether existing rates or charges collected by any public utility for any jurisdictional sale are “unjust, unreasonable, unduly discriminatory or preferential.”[114] Section 206 requires that, upon finding that existing rates are unjust and unreasonable, the Commission “shall determine the just and reasonable rate . . . to be thereafter observed and in force . . ..”[115] The Commission has held that, under Section 206 of the FPA, it has the “responsibility” to fix the just and reasonable rates for jurisdictional sales of power.[116]

In its November 1 Order, the Commission found “that the existing [California power] market structure and market rules, in conjunction with an imbalance of supply and demand in California, have caused and, until remedied, will continue to

---

[113] July 25 Order, 96 FERC at 61,520.

[114] 16 U.S.C. § 824e (1994).

[115] *Id.*

[116] *San Diego Gas & Electric Co.*, 93 FERC ¶ 61,121, 61,367 (2000) (“November 1 Order”).

have the potential to cause, unjust and unreasonable rates . . . ."[117] The Commission found that there was clear evidence that the California market structures and rules provide the opportunity for sellers to exercise market power when supply is tight and can result in unjust and unreasonable rates under the FPA. The Commission therefore proposed specific remedies to address the dysfunctions it found in California's wholesale bulk power markets.

Furthermore, NPG asserts that in its December 15 Order, the Commission, hearkening back to the language in *Farmers Union Central Exchange Inc. v. FERC,*[118] stated that rates must fall within a zone of reasonableness, where the rates are neither so low as to be "less than compensatory" nor so high as to be "excessive" to consumers.[119] In *Farmers Union,* the Court of Appeals explained that:

> When the inquiry is on whether the rate is reasonable to a producer, the underlying focus of concern is on the question of whether it is *high* enough to both maintain the producer's credit and attract capital. To do this, it must, *inter alia*, yield to equity owners a return "commensurate with returns on investments in other enterprises having corresponding risks, "as well as cover the cost of debt and other expenses . . . [W]hen the inquiry is whether a given rate is just and reasonable to the consumer, the underlying concern is whether it is *low* enough so that exploitation by the [regulated business] is prevented.[120]

The Court went on to explain that, while the "delineation of the 'zone of reasonableness' in a particular case may, of course, involve a complex inquiry into a myriad of factors . . . the most useful and reliable starting point for rate regulation is an

---

[117] *San Diego Gas & Electric Co.*, 93 FERC ¶ 61,121, 61,366 (2000) ("November 1 Order"); *see id*. at 61,349-50.

[118] 734 F.2d 1486 (D.C. Cir. 1984).

[119] *San Diego Gas & Electric Co.*, 93 FERC, ¶ 61,294 at 61,998 (2000)("December 15 Order").

[120] *Farmers Union*, 734 F.2d at 1502, quoting *City of Chicago v. FPC*, 458 F.2d 731, 750-51 (D.C. Cir. 1971.

inquiry into costs. . . . [And while] non-cost factors may legitimate a departure from a rigid cost-based approach . . . . 'each deviation from cost-based pricing [must be] found not to be unreasonable and to be consistent with the Commission's [statutory] responsibility.'"[121] In essence, the Court held that, at least as a starting point, and absent evidence to the contrary, prices are "excessive" to the extent they exceed costs plus a reasonable return on capital.

In its December 15 Order, the Commission found that the "[t]he electric power situation in California has worsened since our November 1 Order was issued and it is critical" that immediate steps be taken.[122] The Commission found that, unless remedial measures were taken, "wholesale markets will continue to be dysfunctional."[123] In making this determination, NPG asserts, the Commission satisfied the requirement set forth in Section 206 of the FPA,[124] that it first must find that existing rates are unjust and unreasonable before it may determine and fix the just and reasonable rates. The Commission then determined and fixed the just and reasonable rates by, *inter alia*, establishing a "benchmark price" for certain wholesale sales in California.

In its April 26 Order, the Commission instituted a "west-wide" investigation under Section 206 "into the rates, terms and conditions of public utility sales for resale of electric energy in interstate commerce in the WSCC."[125] After holding a public hearing and receiving comments on the justness and reasonableness of electricity rates in the WSCC, including the Pacific Northwest, the Commission found: "There is a critical interdependence among the prices in the ISO's organized spot markets, the prices in the bilateral spot markets in California and the rest of the West, and the prices in forward markets."[126] Thus, NPG contends, the Commission has already concluded that "a critical interdependence" exists among "the ISO's organized spot markets," which it found "dysfunctional," and "bilateral spot markets" in "the rest of the West," including

---

[121] *Id., quoting Mobil Oil Corp. v FPC,* 417 U.S. 283, 308 (1974).

[122] *San Diego Gas & Electric Co.,* 93 FERC at 61,981.

[123] *Id* at 61,982.

[124] 16 U.S.C. § 824e.

[125] April 26 Order, 95 FERC at 61,365.

[126] June 19 Order, 95 FERC at 62,547.

the Pacific Northwest, and even "the prices in forward markets" in California and the rest of the West.[127] Furthermore, the Commission found:

> What is clear, however, is that a major contribution to the high prices was the deficient market mechanisms initially established by California, and approved by the Commission, that have resulted in a dysfunctional market place both in California and the remainder of the West.[128]

Therefore, the Commission, after months of inquiry, determined that the “deficient market mechanisms” in California led to “a dysfunctional market place both in California and the remainder of the West,” including the Pacific Northwest. According to NPG, it is not the purpose of this preliminary evidentiary proceeding, which the Commission ordered conducted under very serious time constraints, to examine and redetermine, yet again, that the Pacific Northwest spot markets are integrated with, and the prices in those markets were rendered dysfunctional and unjust and unreasonable by, the operations of the California spot markets. NPG avers that the Commission has found that prices charged for spot market sales in the Pacific Northwest were unjust and unreasonable.

Moreover, in its June 19 Order, the Commission took action as a result of its Section 206 investigation findings and "prescribe[d] price mitigation for spot markets throughout the West."[129] Before it could determine and fix just and reasonable prices in the Western spot markets, the Commission had to find, as required by Section 206, that the prices in the spot markets throughout the West, including the Pacific Northwest, were unjust and unreasonable.[130] As noted, in the June 19 Order, the Commission found “a

---

[127] *See also id.* at 62,556 (finding that "spot markets" in California and the WSCC "are integrated").

[128] *Id* (emphasis added).

[129] June 19 Order, 95 FERC ¶ 61,418 at 62,545.

[130] As the Supreme Court has stated, "[t]he condition precedent to the Commission's exercise of its power under [FPA Section] 206(a) is a finding that the existing rate is 'unjust, unreasonable, unduly discriminatory or preferential.'" *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 353 (1956). *See Papago Tribal Utility Authority v. FERC,* 610 F.2d 914, 923 (D.C. Cir. 1979) ("condition precedent" to Commission's exercise of

(continued...)

dysfunctional market place in California and the remainder of the West."[131] The Commission further acknowledged making such a finding when it stated that its prescribed price mitigation "will guide the WSCC's energy markets through the difficult process of self-correction."[132] Accordingly, unjust and unreasonable prices not only "may" have been charged for spot market sales in the Pacific Northwest for the period December 25, 2000 through June 20, 2001, the Commission has in fact found that unjust and unreasonable prices were charged during that period for such Pacific Northwest spot market sales.

On July 25, 2001, the Commission established a method for calculating the just and reasonable clearing prices that should have been charged in the California markets for the period while those markets were dysfunctional.[133] In keeping with the teachings of *Farmers Union*, the Commission established a method for determining the just and reasonable prices that was based on the marginal *costs* plus certain *cost* adders for operations and maintenance, and creditworthiness. The Commission established a further proceeding to determine appropriate refunds based on that just and reasonable pricing methodology.

In the same July 25 Order, the Commission established the instant "preliminary evidentiary" proceeding to facilitate the development of a factual record "to determine the extent to which the dysfunctions in the California market may have affected decisions in the Pacific Northwest."[134] The testimony and exhibits admitted in this proceeding, NPG alleges, confirm the Commission's finding that "the deficient market mechanisms initially established by California . . . resulted in a dysfunctional

(...continued)
powers under Section 206(a) is a finding that existing rate is unjust and unreasonable); *Sea Robin Pipeline Co. v. FERC*, 795 F.2d 182, 187 (D.C. Cir. 1986) (Commission may only order prospective relief under comparable Section 5 of Natural Gas Act "if it finds a previously accepted provision unlawful").

[131] June 19 Order, 95 FERC at 62,556.

[132] *Id.* at 62,545.

[133] July 25 Order, 96 FERC ¶ 61,120 at 61,516-19.

[134] July 25 Order, 96 FERC at 61,520.

market place" in the Pacific Northwest,[135] and that "[b]uyers in the Northwest paid outrageous prices for power that caused much economic dislocation."[136]

There is substantial evidence in the record in this proceeding NPG asserts, confirming that (1) the Pacific Northwest and California operated as an integrated market; (2) Pacific Northwest spot market prices and daily price indices such as the Dow Jones Mid-Columbia Electricity Price Index were significantly affected by the prices in the dysfunctional California spot markets; and (3) the Pacific Northwest spot market prices were well-above prices that would have reflected the sellers' marginal costs, resulting in excessive charges of approximately $2 billion during the December 25, 2000 through June 21, 2001 refund period identified by the Commission.[137]

Both NPG witnesses and TFG witnesses testified that the California and Pacific Northwest markets were integrated.[138] California's witness, Dr. Frank Wolak, similarly testified that "California and the Pacific Northwest are best thought of as a

---

[135] June 19 Order, 95 FERC at 62,556.

[136] July 25 Order, 96 FERC at 61,522 (Massey, Comm'r, dissenting in part and concurring in part).

[137] *See* July 25 Order, 96 FERC at 61,520 n.75.

[138] For NPG witnesses, *see, e.g.*, McCullough Rebuttal Testimony, NPG-68 at 18 ("[f]or most of the year . . . the Pacific Northwest is part of the California market"); Movish, NPG-45 at 13, line 5 (discussing "'spillover' effect" between California and Pacific Northwest "sub-market[s]" of the WSCC); Saleba, NPG-53 at 5 (discussing the "influence" and "impact" of California prices on other subregions in the WSCC). For the TFG witnesses, *see, e.g.*, Van Vactor, ENR-1 at 7-8 ("dependence on seasonal exchange has also created a single continuous market"); Adamson, ENR-10 at 19 ("[t]he PNW market is generally integrated with other sub-regional markets in the WSCC"); *id.* at 23 ("the PNW spot market is a component of a larger market that extends to California, the Rocky Mountain States and the desert Southwest"; Jones, PPL-1 at 17-18, lines 19-20 (acknowledging "the close correspondence between price movements in California and the PNW"); *see also* Puget Complaint at 7 ("California and the Pacific Northwest are part of the substantially integrated wholesale power market of the Western Interconnection").

single integrated market."[139] There is overwhelming evidence in the record in this proceeding that confirms the Commission's previous finding that California and the WSCC market are integrated, NPG maintains.[140]

Additionally, NPG argues that the record is replete with evidence that the dysfunctional prices in the California spot markets substantially affected Pacific Northwest spot market prices and daily price indices.[141] Dr. Wolak explained:

> Particularly during the winter and spring of 2001, there were very few hours when there was congestion from the Pacific Northwest into California. Even during the summer of 2000, there were few hours when there was congestion from the Pacific Northwest into California. For this reason, when prices in California reflected the exercise of market power, prices in the Pacific Northwest were at the same and often higher levels.[142]

In particular, the high prices in the dysfunctional California spot markets drove up the prices of the longer term, *e.g.*, daily, weekly, monthly, quarterly, and yearly standardized products traded in the Pacific Northwest spot market.[143] As Mr. McCullough testified, "while the causes may be subjective, the logical implication is that,

---

[139] CAL-5 at 10, lines 4-5.

[140] *See* June 19 Order, 95 FERC at 62,556.

[141] *See, e.g.,* McCullough, NPG-1 at 9 ("[s]ince May 2000, the centralized markets in California have been the basis of pricing throughout the WSCC"); Movish, NPG-33 at 13, NPG-45 at 13 ("the higher [California] auction prices resulted in a 'spillover' effect into the PNW sub-market. PNW power suppliers were able to price at the CAISO and PX price. Prices would have been lower in a functionally competitive market"); Saleba, NPG-53 at 3 ("Because California has such a strong influence in the WSCC, price movements in California tend to have an immediate impact on prices in other sub regions.").

[142] Wolak, CAL-5 at 9, lines 14-20.

[143] *See* McCullough, NPG-1 at 9 ("the opportunity cost of the [California] hourly market clearly drives longer term offers elsewhere in the WSCC"); *id*. ("[a]fter May 2000, the correlation between short term and long term prices has increased).

as fundamentals declined in value as an explanation for prices in California, traders were forced to depend increasingly on trends in their estimates of future prices"), NPG argues.[144]

The prices in the California spot markets similarly affected the Pacific Northwest daily price indices, such as the Dow Jones Mid-Columbia Price Index. The Commission staff, examining peak prices for the summer 2000 period, found that

> "[t]he correlations between California PX prices and western market bilateral prices are quite strong . . . . Mid Columbia (prices) are highly correlated as are CalPXSP15 and Palo Verde because of the geographic proximity of the points and the general absence of transmission limits into California."[145]

Data from December 2000 and January 2001 shows the continued strong correlation between California prices and Mid-Columbia and California-Oregon Border ("COB") prices, demonstrating that "sellers of electricity will arbitrage any significant price difference between the Pacific Northwest and California."[146]

Thus, in the very few weeks that have been provided for this preliminary evidentiary hearing, NPG states, the parties have produced substantial evidence confirming the Commission's earlier findings that the prices in the dysfunctional California spot markets directly affected the Pacific Northwest spot market prices and daily price indices.

NPG maintains that its members have submitted substantial evidence that prices they paid in the Pacific Northwest spot market during the refund period were significantly above benchmarks based on the marginal cost of the last unit that would have been dispatched absent the price distortions in the California PX and ISO spot markets or that was dispatched, and therefore that such charges were unjust and unreasonable. On behalf of Seattle City Light, Mr. McCullough determined the marginal

---

[144] *Id.* at 9; *see id.* at 9-10 (discussing and graphing the correspondence between Dow Jones daily prices and the related third quarter bids to Seattle).

[145] Staff Report to the FERC on Western Markets and the Causes of the Summer 2000 Price Abnormalities, November 1, 2000 at p. 3-8, quoted in Movish, NPG-33 at 13, NPG-45 at 13.

[146] Wolak, CAL-5 at 10; *see* CAL-7 (showing data in bar graph form).

cost of the highest cost unit that would have been dispatched to meet actual load during the refund period absent the California spot market dysfunctions.[147] Mr. McCullough determined the benchmark price for each month in the refund period.[148] Applying these benchmark prices to its actual sales and purchases, Seattle City Light determined that it was a net purchaser and would be entitled to refunds totaling $278 million.[149]

On behalf of Tacoma, the Port and Northern Wasco, Mr. Movish determined a mitigation price similar to that used in California by the Commission, but modified in certain respects to reflect characteristics of the Pacific Northwest.[150] Using this mitigation price reflecting the marginal cost of the marginal unit, Tacoma, the Port and Northern Wasco calculated that they were entitled to refunds totaling $65,407,755; $9,371,660; and $4,089,364, respectively.[151]

In calculating their potential refunds in this proceeding, the California parties used the unadjusted mitigated market clearing prices calculated by the California ISO and submitted in Docket No. EL00-95-045 on August 9, 2001.[152] Using this benchmark price, the California parties determined that they paid $1,466,098,964 in charges above the just and reasonable rate adopted by the Commission for California.[153]

In calculating its amount of potential refunds, the Eugene Water and Electric Board ("EWEB") used as its benchmark price the non-emergency hour

---

[147] *See* Part II.F.1 *infra* (describing this benchmark in detail).

[148] *See* Exh. NPG-1 at 16-17.

[149] Item by Reference NPG-70 at 2, para. 1.d.

[150] *See* Part II.F.2, *infra* (describing Mr. Movish's benchmark in detail).

[151] *See* Movish, Exh. NPG-33 at 24-25; Movish Exh. NPG-45 at 24; Winters, Exh. NPG-43 at 12; Item by Reference NPG-71 at 25.

[152] William Green, Exh. CAL-1 at 3, lines 1-2 and 6, lines 9-23.

[153] Exh. CAL-1 at 7, line 1.

mitigation price of $91.87 calculated by the California ISO.[154] EWEB found that it had incurred charges of $39,719,000, [155] over this benchmark price.

The Sacramento Municipal Utility District ("SMUD") calculated its potential refund amount using its "estimate of the ISO's hourly market mitigation clearing price."[156] Using this benchmark, SMUD calculated its potential refund to be $4,587,511.72.[157]

In sum, the parties who, to date, have calculated the potential net refund amounts described above have done so using mitigated prices or "benchmarks" based on the marginal cost of the last unit that would have been dispatched, absent the price distortions in the California markets, or was dispatched. These benchmarks are either identical or akin to that used by the Commission in the California refund proceeding as the demarcation line between fair and reasonable, versus unjust and unreasonable, prices. The parties have thus submitted substantial evidence of unjust and unreasonable charges which, as the Commission staff found, merits further proceedings.[158] The total extent of potential refunds claimed to date is $1,931,354,858, as set forth in Commission Staff Exh. S-8, from which the following summary is taken:

[154] *See* Spettel, Exh. NPG-74 at 12.

[155] S*ee* Commission Staff Exh. S-8; Spettel, Exh. NPG-74 at 12, lines 3 through 5.

[156] Exh. SMD-1 at 4, lines 4-5.

[157] *Id.* at 2.

[158] *See* Poffenberger, Exh. S-3 at 10.

California Parties	$1,466,098,964
City of Seattle, Washington	$278,000,000
City of Tacoma, Washington	$65,407,755
Clark Public Utilities	$64,080,603
Eugene Water and Electric Board	$39,719,000
Northern Wasco County People's Utility District	$4,089,364
Port of Seattle, Washington	$9,371,660
Sacramento Municipal Utility District	4,587,512
TOTAL	$1,931,354,858

CALIFORNIA PARTIES:

According to the California Parties, the record in this case establishes unequivocally that unjust and unreasonable prices were charged for spot market bilateral sales in the PNW during the refund period. The TFG's arguments to the contrary erroneously assume that the PNW market was not affected by the documented dysfunction in the California market, and that the extraordinarily high PNW prices merely represented the operation of a distinct and "workably competitive" market. These claims disregard the obvious and are unsupported by the record in this case.

***TFG*:**

TFG maintains that even if one were to ignore the serious legal prohibitions on directing retroactive refunds, any effort to argue that unjust and unreasonable prices may have been charged, can only proceed on the strength of a full understanding of the unique characteristics of the PNW market and the context in which prices evolved during the period from December 25, 2000 through June 20, 2001.

The PNW is part of the broader Western power market. The purchase and sale of electricity is carried out pursuant to the rules and guidance of the WSPP. Implementation of the WSPP Agreement was first approved in 1987, but for decades previous the PNW has enjoyed a robust and liquid wholesale power market, which is characterized by hundreds of informed and experienced traders and multiple trading points. *See* Exh. ENR-1 at 3; Exh. AE-1 at 3; Western Systems Power Pool Agreement, Exh. S-6 (Original Sheet No. 91, Rate Schedule FERC No. 6, at 101-103). As Seattle's own witness Mr. McCullough testified:

> The Pacific Northwest operates as a true commodity market where prices are set by bilateral negotiations, rather than administered by a separate authority. In this way, the Pacific Northwest far more closely approximates true commodity markets like the Chicago Board of Trade or the London Metal Exchange.
>
> Exh. NPG-1 at 7:14-17.

Several factors explain this phenomenon. In terms of energy resources, over 60% of the PNW's power supply comes from hydroelectric facilities in a typical year. Exh. ENR-1 at 8; Exh. ENR-5. While the prevalence of hydroelectric generation provides a distinctly inexpensive source of power, it also subjects load serving entities to the vicissitudes of weather (*i.e.,* drought and resulting low-flow conditions). Faced with seasonal and year-to-year variations in water and storage availability, PNW parties have long been accustomed to buying and selling with each other and with parties outside the region to ensure that supply matches demand. Exh. AE-1 at 3.

Following construction of the Northwest-Southwest Inertia in 1970, seasonal exchanges of power with California, Arizona and New Mexico became commonplace. The normal water flow from May to July, coupled with a winter peaking demand profile, has enabled the PNW to export large volumes of "economy" energy during summer months, when its loads are low, but loads to the south are at their highest levels. In return, the PNW historically has relied on surplus thermal generation from California and the Desert Southwest to supplement local supplies during winter cold spells, when loads to the north are high in comparison to loads to the south. Exh. ENR-1 at 9.

The presence of an extensive and comparatively uncongested transmission network (on a historical basis) also has contributed to the development of a fluid wholesale power market in the PNW. BPA owns and operates the majority of the high voltage transmission facilities in the region. Long before the advent of Commission Order No. 888,[159] BPA allowed parties access to its transmission grid. Exh. AE-1 at 3.

---

159 *Promoting Wholesale Competition Through Open Access Non-discriminatory*
(continued...)

As a consequence, the Mid-Columbia hub in Eastern Washington is recognized as one of the most flexible trading points in the nation. Exh. ENR-1 at 12.

Because a robust bilateral wholesale market evolved on its own, there has never been a centralized power exchange in the PNW. As a result, there is no single market clearing price in the region. Exh. ENR-10 at 12. Instead, energy is bought and sold continuously on a bilateral basis, subject only to the principles set forth in the WSPP agreement. Each utility is free to choose how to meet its firm load requirements as it sees fit and no one is captive to a single market or a single point of supply. As noted by Eugene Water and Electricity Board ("EWEB") witness Spettel, transactions "are negotiated at arms-length between willing buyers and sellers … [and] oftentimes reflect unique and specific circumstances between the parties engaged in each transaction." Exh. NPG-68 at 7. See also TR. at 566-67; Exh. ENR-1 at 13; Exh. PWX-1 at 21; Exh. BPA-1 at 22; Exh. ENR-10 at 11; Exh. IE-2 at 13; Exh. PPL-1 at 21.

Given the availability of many traders and trading points, purchasers in the PNW have numerous options in developing a portfolio of power supply. Depending upon their perceived needs and tolerance for risk, load-serving entities can buy power for the next hour, the next day, the balance of the month, monthly, quarterly or for a term of one or more years. Exh. NPG-74 at 6. As observed by Dr. Tabors, risk-averse load-serving entities can assemble a portfolio of long, medium and short-term contracts and, thereby, minimize their exposure to volatile spot market prices. Exh. PWX-1 at 21. In the PNW, shortages in the availability of hydroelectric generation are constantly assessed and general trends are predicted months in advance, consequently PNW purchasers tend to make extensive use of forward contracts (*i.e.*, transactions with durations longer than 24 hours). Indeed, over 99% of the City of Seattle's net purchases during the December 25, 2000-June 20, 2001 period were made under forward contracts; the corresponding figure for Tacoma Power approximates 62.5%. Exh. PWX-3.

Two additional characteristics of the PNW market are directly relevant to the justness and reasonableness of bilateral spot market prices in the region. First, demand in the region is more price sensitive (that is to say, "elastic") than in other parts of the West due, in part, to the presence of a number of energy intensive industries, such as aluminum smelting. Exh. ENR-1 at 11. Those consumers have exercised and, indeed,

---

(...continued)
Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) ("Order No. 888").

regularly exercise their ability to respond to price signals by decreasing consumption. Demand responsiveness by PNW consumers was a very important factor in bringing prices down in the PNW in 2001, and an important indicator that the PNW markets were functional throughout the potential refund period. Second, prices, particularly in the forward markets, are extremely sensitive to movements in the cost of natural gas. Exh. ENR-10 at 24-27. It is, therefore, not surprising that electric prices rose dramatically in the PNW when increased demand for natural gas caused prices to skyrocket in the latter part of 2000, as drought conditions restricted the availability of hydroelectric generation.

The Commission's decision to address refunds in Docket No. EL00-95-004 (the "California proceeding") was based, at least in large measure, on its conclusion that the "electric market structure and market rules for wholesale sales of electric energy in California were seriously flawed."[160] The Commission found problems with (i) California's implementation through the ISO and PX, of a mandatory single price auction mechanism, and (ii) the exclusive reliance on spot market (less than 24 hour) trades for purposes of establishing that price. These problems distorted and exacerbated the effects of high prices that resulted when supply was tight. Of particular relevance to this investigation, the Commission expressly declined to impose refund liability on bilateral purchases of the CDWR after the PX closed its doors:

> We believe imposing after-the fact refund liability on California transactions outside of the centralized ISO and PX markets is unjustified. This is particularly true in the instant proceeding when the Commission consistently encouraged California load-serving entities to acquire a balanced portfolio of short, medium and long-term contracts. Expanding the scope of transactions subject to refund over the period October 2, 2000, through June 20, 2001 to include transactions outside the ISO and PX centralized markets would simply hinder the ability of parties to enter into new bilateral contracts.[161]

Multiple requests for rehearing have been filed in the California proceeding and the disputed issues addressed therein cannot and should not be relitigated here. TFG argues that what can be said – indeed, must be said – is that the Commission's rationale in its July 25 Order for ordering refunds in the California ISO and PX centralized spot

---

160
November 1 Order, 93 FERC at 61,349.

161 July 25 Order, 96 FERC at 61,515.

markets is simply not applicable to the PNW market, but its reasoning regarding bilateral contracts is compelling outside those markets.

The factual differences between the California ISO/PX markets and the PNW market are stark and self-evident. In California, load-serving entities (comprised almost entirely of California's three large investor-owned utilities) were forced to divest much of their generation, to sell power from what generation remained to the ISO/PX and then buy back all of their requirements through a centralized clearing house at an administratively determined price. Because that price was tied to the bid of the most-expensive generating unit operating within the market at the time, it did not necessarily reflect the value placed on those transactions by any individual buyer. Exh. PWX-1 at 16. In addition, having to rely entirely on spot market sales, California buyers were effectively prevented from hedging their risks or balancing their portfolio through forward contracts. In its November 1, 2000 Order,[162] the Commission expressly found this to be a fundamental problem with the California market. Exh. ENR-10 at 11.

In sharp contrast, buyers in the PNW faced no such constraints. Load-serving entities, for the most part, retained their own generation, were free to negotiate supply contracts on their own terms and conditions in spot and forward markets, and, as a consequence, paid prices that reflected the value that willing buyers and sellers placed on those transactions in the face of supply constraints. Exh. PWX-1 at 16. For many years PNW buyers have been free to enter into short, medium, and long-term contracts to achieve a hedged and balanced portfolio. It is undisputed that "participants in PNW markets made their own decisions regarding purchasing strategies and contract terms, not only in the period covered by this proceeding but for years leading up to this period." Exh. PWX-1 at 6:14-16. The participants "made numerous conscious decisions regarding their electricity supply strategy in the years and months prior to the period covered by this proceeding, as well as the during the period itself." *Id.* at 7:8-10.

All of the credible testimony shows that a confluence of unprecedented demand and supply conditions in the PNW led to increased electricity prices during December, 2000 to June, 2001.

The hearing record documents in detail the successive shocks that the western power market experienced leading up to and during the period at issue:

> The disruption and price explosion in the WSCC from May 2000 through June 2001 were the consequence of market fundamentals,

---

[162] November 1 Order, 93 FERC at 61,359.

> exacerbated by financial uncertainty and confusion. There were four compounding events that caused price to rise and to remain at elevated levels for fourteen months. In the first wave, the summer of 2000, high demand growth and hot weather combined to create capacity shortages in California, with resulting price spikes. In the second wave, cold weather smacked the PNW earlier than expected and with much greater severity than normal. The cold weather coincided with the season in which the natural stream-flow in the region's hydro system is at its lowest, and with the planned reconditioning of many of California's thermal generators due to heavy usage in the summer of 2000. The natural gas delivery system was stretched to its limit, inventories reached historic lows, and gas prices peaked at thirty times the level of the year before. In November and December, precipitation remained at record low levels and the power industry became increasingly anxious about the possibility of a serious drought. The Power Planning Council's October warning appeared all the more prescient. In January 2001, the first formal projections on snow pack became available and provided alarming evidence of dry conditions, bringing a third wave of dread to the Western power market. In the meantime, PG&E and Southern California Edison were not able to pass on to their customers the high prices they had had to pay for power in November and December due to frozen rates imposed during market restructuring. Both utilities defaulted on their obligations to their suppliers, including many PNW utilities. The growing financial risk created the fourth and final wave, as essential trade shrunk and the WSCC split apart in autarky.

Exh. ENR-1 at 19:13-20:11.

TFG continues to assert, assailed by these shocks, the PNW market did not malfunction, as did the California market. To the contrary:

> The PNW was faced with an extreme and rare contraction in available supply. To accommodate the shortage, prices rose dramatically, but that is exactly what they are supposed to do. Higher prices provoked a drop in demand and an increase in alternative supplies. Once it was clear that the functions of demand and supply would accommodate the projected shortfall, prices collapsed with extraordinary speed.

Exh. ENR-1 at 19:13-21:1; *see also* Exh. NPG-16 at 16:327-17:349; Exh. IE-2 at 2:22-3:4; Exh. IE-4, Appendix F.

The market for electricity in the PNW was affected to varying degrees by these factors, all of which worked together to raise the price of electricity as is normally expected in a workably competitive market when supply is scarce.[163]

Importantly, the evidence also establishes that the PNW utilities were generally forewarned of potential supply shortages:

> Power supply in the region is tied irrevocably to precipitation in drainage areas of the Columbia River. From 1996 through 1999, weather patterns had produced a series of above average water flows and the surplus generation was giving misleading signals. It had been over two decades since the region had experienced a major drought, population growth had increased demand and, perhaps unknowingly, the PNW had become increasingly dependent on seasonal trade. Moreover, declining salmon runs and the risk of species extermination had caused the region's policy makers to shift focus. The commitment to save the salmon, however, required the PNW to implement new and untested hydroelectric operational modes.
>
> Early in 1999 the BPA Administrator met with the Power Planning Council ("Council") and expressed concern that the region showed an energy deficit even under normal water conditions. On page 2 of the Council['s] "Northwest Power Supply Adequacy/Reliability Study" of March 6, 2000, it was reported that the BPA study revealed that in eighty percent of the simulated historical water flows there was a projected deficit averaging 2,500 megawatts per hour for September while thirty-six percent of the scenarios for the month of February had an average deficit of 3,800 megawatts per hour. On page 3, the Council reported that its own analysis had reached nearly identical conclusions. . . . The Council's white paper was accompanied by a "Keep The Lights On" conference attended by executives from many PNW utilities. At the conference the BPA Administrator again warned of inadequate supply. Moreover, the audience was warned about the impact of fish preservation requirements on dam operations as well as planned

---

[163] Dr. Cicchetti testified: "Dr. Wolak and others ignore this competitive market price signal function, which only works when conditions that drive up prices such as excess demand, short term supply or both, are allocated to signal the need for new investments by prices (MCP) that exceed short-run marginal cost and ATC. This outcome is efficient and serves a valuable public policy function." Exh IE-2 at 25-26.

> curtailments of the federal transmission system. In its March 6, 2000 edition, *Clearing Up* reported that Seattle City Light Superintendent Gary Zarker took the threat of shortages seriously and "that the region should approach the reliability situation 'as if the crisis had already occurred.'"
>
> Exh. ENR-1 at 13:22-15:2.

TFG asserts that even the refund claimants' evidence establishes that drought conditions were severe and affected wholesale electrical energy prices:

- "While power prices have been high, the Pacific Northwest also experienced one of the driest years on record which in turn reduced the amount of power available from Pacific Northwest hydroelectric projects . . . Power prices would be expected to be lower in years where more normal precipitation increases the supply of electricity, thus depressing power prices in average or better-than-average hydrological conditions." Exh. NPG-74 at 9:21-10:5.

- "In October, 2000, the utility received less than normal rainfall, and in November and December our drainage basin received significantly less than half of the statistical average precipitation for these months . . . These shortfalls forced SCL on the market for additional purchases at even higher prices." Exh. NPG-4 at 14:305-310.

- "The ultimate blow to the western wholesale electricity market came when winter rains failed to materialize. A dry fall turned into a dry winter and left the Pacific Northwest running on empty reservoirs by spring. The traditional trading patterns between California and its northern neighbors – electricity shipped from the Northwest to California in the summer and returned by California to the Northwest in the winter – failed." Exh. NPG-16 at 16:361-366.

TFG points out that NPG witness Ms. Green testified, Seattle would typically prepare for potential electricity shortages by monitoring water levels:

> **Q:** Do you know when Seattle City Light realized that low water year was about to materialize for 2001?

> **A :** Most of our precipitation comes in the months of October through March, so October was the first month in which we were expecting significant precipitation in which it did not occur. In November, we had a similar shortfall. In December, we also had a shortfall. And then, as my testimony indicates, the snow surveys that we viewed, and have done for 50 years, showed a declining water position every month that we measured the snow.

Tr. at 592:19-593:4.

As Ms. Green and others acknowledged, in 2000 and 2001, the PNW experienced the worst drought in the last 50 years. See Tr. at 592:19-593:4; *see also* Tr. at 610:20-611:10. Combined with increased demand from population and technology growth ("one dot-com company can use 20-40 megawatts per day, the same as the entire [Seattle-Tacoma] airport."), this drought caused an unprecedented increase in prices. Tr. at 610:20-611:10. The record also establishes that increased demand for electricity contributed to increased input costs (*i.e.*, higher demand for electricity resulted in higher demand for natural gas, causing the price for gas to increase). *See* Exh. ENR-10 at 28:4-5, 12-15 ("In addition to dramatic changes in market conditions for natural gas in the Northwest, a second major factor that must be considered is the impact of hydrological conditions…. Just as the natural gas market was making it more costly to offer forward electricity contracts, the weather was reducing the ability of hydroelectric operators to enter into such forward commitments. Available supply was therefore contracting, which put further upward pressure on prices.").

In addition, in California, increased demand, unavailable generation, and credit concerns with California buyers all exacerbated the situation. As Clark Public Utility's witness Gary Saleba testified:

> Several factors combined to exacerbate the problem: the fact that significant amounts of capacity were out of service in California for maintenance or other reasons; the fact that financial crises facing California's two largest purchasing entities (both IOUs) led some sellers to withhold supply because of inadequate credit assurances; and the collapse of the California PX Day Ahead market.

Exh. NPG-53 at 5:4-10.

The record evidence amply demonstrates that the PNW market for spot sales of electrical energy was at all times between December 25, 2000 to June 20, 2001 competitive and functional. Dr. Tabors explained why:

> [P]rices within the Pacific Northwest are established through bilateral contracts. Buyers are not captive to a single market and certainly not a single point of supply. There are multiple trading points in the Pacific Northwest and individual trades can take place at any other point that the two trading partners might choose. The result is that the structure of the Pacific Northwest spot market is functional and is inherently more competitive and far more flexible than was or is the California spot market. Participants in the Pacific Northwest market had a vast number of alternatives for purchases that were not available in the California market.

Exh. PWX-1 at 20:16-21:3.

Dr. Tabors' analysis and conclusion is fully consistent with that of other experts. Dr. Jones explained that, the "classic definition of a competitive market is a market that relies on the interaction of many informed buyers and sellers such that no single buyer or seller can institute and profitably sustain a significant increase in price." Exh. PPL-1 at 7:12-14. Using this rule, Dr. Jones found no evidence to support claims that the PNW market was other than workably competitive:

> Based on my analysis, I conclude . . . the actions of sellers and the prevailing prices in the PNW are fully consistent with a competitive market and are an attempt on the part of buyers and sellers to allocate scarce resources efficiently.
>
> *   *   *
>
> There has been no showing of market power or other evidence indicating members of the TFG did any thing other than reflect their competitive market expectations in their bilateral contracts.

Exh. PPL-1 at i.

Dr. Jones explains that in the PNW, buyers and sellers of wholesale electricity can, at any time, negotiate using established and transparent terms. *Id.* at 7:14-18. He showed that prices during the relevant period were a function of normal supply and demand conditions, which were largely unprecedented:

> The prices set by the marketplace from December 2000 through June 2001 reflect the actions of buyers and sellers in a competitive market responding to forces other than market power.
>
> * * *
>
> [A]fter years of abundant generation capacity that caused prices to remain low, the market began to change in the late 1990's as continued growth in electricity demand began to 'bump against' the ability of low-cost generators to meet peak load requirements at existing prices.

Id. at 12:15-14:13; 29:12-15; 13:15-18.

However, Dr. Jones, along with nearly all other witnesses, determined that the PNW market, confronted with these conditions, performed just as a workably competitive market would, TFG avers.

- "As prices increased during 2000-2001, investors/suppliers responded, proposing new capacity additions. On the demand side of the price signal, consumers went to work, reducing energy use and adopting conservation techniques…. As a consequence of this competitive response, prices for electricity in the PNW have fallen dramatically." Exh. PPL-1 at 14:7-13.

- "Notwithstanding the shortages of energy in the Pacific Northwest, the market was sufficiently competitive to enable purchasers to be selective about the energy product that they were purchasing. As a consequence, purchasers were able to dictate certain key terms of transactions to sellers, such as firmness and point of delivery." Exh. PSCO-1 at 11:12-16.

- Port of Seattle reported in May 2001, "[m]any experts are forecasting not only sustained periods of high prices but also shortages of electricity in 2001. Staff believes it is critical that we not only take measures to reduce the cost of electricity through conservation…, but find a reliable and stable source of electricity for the Airport's future needs." Exh. TFG-8 at 1, PS 1570.

- Port of Seattle also reported "[f]our different companies have approached us on … the option of self-generation…. Implementing energy conservation projects and programs [has] reduced [our] consumption by over 10% already and may get to 15% in another month. Long term we believe we can reduce energy consumption by 20-25% from our current base." Exh. TFG-5 at PS 1529.

As a result of these fully predictable market responses, the supply and demand were restored to balance in short order. Mr. Van Vactor also explains how the Western power market crises moderated:

> The Western power crisis has alleviated due to a significant drop in consumption. In the PNW, many industrial customers agreed to shut their plants down and sell the power back to the supplier. In California, the long-postponed retail rate increase finally went into effect in June [2001]. That combined with a conservation program dropped demand by more than five percent. At the same time new, and more efficient, generating resources came on-line. Summer weather returned more or less to normal and spot prices have returned to normal levels.
>
> The PNW was faced with an extreme and rare contraction in available supply. To accommodate the shortage, prices rose dramatically, but that is exactly what they are supposed to do. Higher prices provoked a drop in demand and an increase in alternative supplies. Once it was clear that the function of demand and supply would accommodate the projected shortfall, prices collapsed with extraordinary speed. Exhibit ENR-9, compares an index of the price of the third quarter 2001 forward contract power delivered to Mid-C to an index of "Dot-Com" stock prices. Once the western power market corrected it did so with a vengeance reflecting, once again, unpredictable Mother Nature and the awesome power of markets to accommodate her.

Exh. ENR-1 at 20:14-21:6. Dr. Tabors observed the same moderation of the market:

> [T]he bilateral markets in the PNW, . . . which have been in existence for more than two decades, worked through a confluence of adverse circumstances in 2000 and 2001, and have now regained equilibrium. Conservation resulted from price signals, demand was reduced, load was shed,

> and prices came down. These are not indications of a broken market in the PNW, but of one that works. It should be left alone to function.

Exh. PWX-12 at 10:6-11. Additionally, Dr. Jones observed:

> The price signals sent to buyers and sellers in the spot market for electricity in the PNW are sufficiently strong to cause forces to be put into place that will change the structure and nature of the wholesale market so that the price spikes are unlikely to reoccur.

Exh. PPL-1 at 5.

Moreover, on cross-examination, the claimants' witness, Dr. Mason, conceded that sellers who engaged in the business of marketing electrical power face no barriers to entry. *See* Tr. at 770:24-772:3. Dr. Mason testified unconditionally that for sellers who are marketers that "[t]here are no barriers to prevent them [from] buy[ing] and resell[ing]." *Id.* Likewise, another of the claimants' witnesses, Dr. Pechman, admitted that he conducted no econometric or price elasticity studies to support his contention, contrary to the evidence, that demand in the PNW does not respond to price:

> **Q:** Where in your testimony – I'm going to open it up. I want to look at a line or a line or an exhibit in your testimony, where do you prepare and present to this court an economic analysis of the elasticity of demand for wholesale power in the Pacific Northwest market during the period at issue, where?
>
> **A:** I have no such analysis in this testimony.

Tr. at 1030: 2-9. Similarly, Dr. Pechman admitted that he had no evidence to support his assertion that suppliers exercised market power by withholding power from the market:

> **Q:** Let me just ask, in your testimony in this proceeding, do you provide any evidence of joint action by suppliers of wholesale electricity to the Pacific Northwest market during the period at issue? Do you provide any evidence of joint action by suppliers?
>
> **A:** No.

Id. at 1030:20-25.

According to TFG, claimant's arguments are based not on any proof that the PNW market was somehow flawed. In fact, the evidence proves the opposite. Seattle witness Mr. McCullough observed:

> One reason why real world commodity exchanges avoid the administered prices of the California model is that these types of markets have proven relatively easy to manipulate. Manipulation of prices in the WSCC outside of California is difficult since no central authority can be "gamed."

Exh. NPG-1 at 7:19-22. EWEB witness Mr. Spettel echoed this characterization of the PNW:

> While the prices in the Pacific Northwest were higher than expected or desired by EWEB, whether EWEB was a purchaser or a seller in a given transaction, the prices were not a result of unreasonable profit taking or unreasonable leverage exercised by a given seller or sellers in the Pacific Northwest market.

Exh. NPG-8 at 8. Nor do refund advocates seek any structural changes in the operation of the markets governed by the WSPP Agreement:

> **Q:** In fact, you're not advancing any challenge to any of the terms and provisions of the WSP agreement, correct?
>
> **A:** Correct.
>
> **Q:** Are there any provisions that come to mind that you think you'd like to have changed in this proceeding?
>
> **A:** No.

Tr. at 660-661.

Rather, claimants' argument reduces to this: Because prices were high in both California and the PNW and because these markets are integrated, prices in the PNW must have been "influenced" by the "flaws" the Commission found in the ISO and PX spot markets. This argument finds causation where none exists. An imbalance between supply and demand caused the high prices throughout the west. The flawed market structures of California exacerbated the effects of scarcity in California, but they were not the cause in either California or the PNW or the rest of the WSCC.

To date, the Commission has taken a surgical approach to the problems in California.[164] It has determined that structural flaws existed in the ISO and PX spot markets and it purported to design a refund order and mitigation plan to cure those flaws. The Commission has rightly refused to extend refund liability to other California markets in which prices were apparently "influenced" by the ISO and PX prices but where no structural flaws existed. For the same reason, refunds should not be imposed in the PNW. There is no evidence, allegation, or finding that any structural flaw at all existed in the PNW market. The Commission should minimize its intervention in otherwise well-functioning market mechanisms.

In seeking refunds, claimants build their arguments on the existence of high prices alone. In doing so, they are trying to shield themselves from the consequences of their own decisions. There is no doubt that refund claimants were aware of the risks they were taking by increasing their reliance on the spot market to serve load. The Commission has said:

> We emphasize that, by design and definition, spot markets must be allowed to reflect the price swings which capture their temporal nature. In markets such as these, which are the closest to when demand must be met, sufficient supply often manifests itself by dramatic price drops while tight supply can produce dramatic price increases. This is the nature of spot markets. *Those who remain in the spot market for buying their residual load or selling their residual supply should be there in full recognition of the effects on price of last minute sales and purchases*.[165]

Tacoma's witness, Ms. Stegeman, noted explicitly that Tacoma chose to take the risk of high spot market prices. Tacoma chose not to accept the "environmental risk associated with the operation of the coal burning [Centralia] plant," or the risk of being "locked into a long term contract" at prices above the prevailing spot market price. Exh. NPG-57 at 3. Ms. Stegeman even contended that "a utility should be protected by the FERC for market prices if the utility mismanaged the acquisition of its power supply portfolio." Tr. at 692:9-692:12. The evidence is clear that such intervention is not

---

164 *See San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Service into Markets Operated by the California Indep. Sys. Operator and the California Power Exchange*, 95 FERC ¶ 61,115 at 61,352 (2001) (the "April 26 Order") ("price mitigation should be as surgical (least intrusive) as possible and last for as little time as possible").

165 December 15 Order, 93 FERC at 61,996 (emphasis added).

conducive to a competitive market. As Dr. Cicchetti explains: "Those who seek refunds for anomalous years are looking for a 'heads I win, tails you lose' result." Exh. IE-2 at 23:2-8. If the position of the refund claimants is accepted, they would be relieved of the consequences of their conscious economic decisions at the expense of a functioning competitive market in which a vast majority of the PNW purchasers during this period accept responsibility for the choices they made.

Uncontradicted record evidence, TFG avers, demonstrates that parties seeking refunds chose to increase their risks. Unlike California, *no one* in the PNW was forced to rely solely on spot markets. Those who made spot purchases did so voluntarily, both benefiting and losing from their choices as the market moved up and down.

NPG witness Ms. Green testified that in 1996, Seattle City Light had a "surplus generation position of over 250 MW." Exh. NPG-67 at 3. Over the next four years, however, Seattle chose to dismantle that surplus. Seattle reduced the amount of power it was entitled to take from BPA by 100 MW, and sold its 80 MW share of the Centralia power plant. *Id.* Assuming normal water conditions, Ms. Green admitted that these actions reduced Seattle's projected surplus for 2001 to just 22 MW. *Id.* In relation to Seattle's average annual load of over 1100 MW and peak load of 1769 MW, this reserve is only 2% of average load and barely 1% of peak load. This is insufficient for a normal water year and sorely deficient for a drought year. Exh. NPG-4 at 8:179-9:195. Seattle recognized in September, 2000 that the Centralia sale left it "more dependent on the market than we have been historically." Exh. PPL-1 at 21 n.19 (*quoting* Seattle City Light, *SCL Issues Brief: Wholesale Power Market Prices and Seattle City Light Rates*, Sept. 19, 2000, at 2).

Tacoma likewise sold its [80 MW] share of the Centralia production. Tacoma replaced this production with purchases from Powerex and BPA – parties from whom it now seeks refunds. Exh. NPG-57 at 3. Neither Seattle nor Tacoma chose to build or acquire generating capacity to replace the Centralia production until after the consequences of their short position became apparent. Seattle also chose to base its supply plans on what turned out to be overly-optimistic projections of water levels, rather than the conservative assumptions available to it. Tr. at 591:20-25.

Purchase of forward contracts was another option available throughout the PNW to reduce reliance on the volatile spot market. Tr. at 656:15-657:4. In September 2000, TFG member Powerex offered forward contracts for delivery of power during the first quarter of 2001 at $75.50 and $81 per MW. Tr. at 689:11-690:21; Exh. TCE-2. One of Tacoma's industrial customers, Simpson Timber, chose to acquire power on these terms, and thus avoided having to acquire this power at the higher spot market prices prevailing in the first quarter of 2001. Tr. at 691: 9-691:14, 700:10-700:22. Tacoma, however, chose not to do so. Tacoma also received quotations for forward purchases from a number of parties in November 2000, but did not take advantage of them. Tr. at 647:10–649:14; Exh. TFG-9. Despite this, Tacoma now asks the Commission to give it, through refunds, rates it rejected in the marketplace. The evidence shows that the claimants, like Tacoma, essentially want this Commission to absolve them of their conscious decisions. The public interest does not provide for such regulatory interventions.

Finally, TFG asserts that refund claimants increased their reliance on the spot market by managing their own resources to pursue goals other than generation of electricity to meet their loads. Ms. Green's testimony referred to Seattle's need to "serve the environmental expectations of our customers." Exh. NPG-67 at 8-9. Measures to do so included implementation of salmon preservation policies that limited the ability of the hydroelectric power system to shape flows in a given month to meet firm system needs. Exh. ENR-1 at 17-18. Although salutary, such choices have a cost, the obligation for which belongs with Seattle and its customers, not its wholesale suppliers.

For a number of years preceding the refund period, wholesale electricity market prices in the PNW were, according to Tacoma's Ms. Stegeman, "quite low." Exh. NPG-16 at 14. *See* also Exh. IE-2 at 28:15-20. During this time, wholesale electric power was often available in the spot market at lower rates than those available through forward contracts and other long-term arrangements. That is why, for example, Seattle chose in 1996 "to take 100 MW off of its BPA entitlement, the cost of which exceeded the market at that time." Exh. NPG-67 at 3. By electing to rely on the spot market during this period, refund claimants benefited financially (although at the cost of increasing their exposure to the risk of spot market price increases). Tacoma, for example, was able to keep its rate levels unchanged from 1995 to December 2000. Exh. NPG-16 at 12; *see* Exh. PPL-1 at 24 & n.24.

Having now experienced the volatile price increases of the spot market to which they exposed themselves for short-term financial gain, the refund claimants are rebalancing their portfolios by returning to BPA or by acquiring interests in new generation facilities. Seattle has acquired a 100 MW capacity share of a combustion turbine and exercised its right to take its full BPA entitlement. Exh. NPG-67 at 3. A May 2001 Port of Seattle staff analysis concluded that "[b]ecoming a BPA customer is the best long-term strategy for the Airport." Exh. TFG-8 at 2; *see* Tr. at 614:18-614:25. Tacoma has installed a 48 MW diesel generation project and entered into exchange agreements with other power suppliers. Exh. NPG-15 at 18; Exh. NPG-57 at 5. These responses by refund claimants are proof positive that the market is functioning properly and that it continues to offer choices to its participants. The refund claimants could easily have taken these risk-reducing steps sooner; for reasons of their own, they decided not to do so.[166] They should not now be reimbursed through an after-the-fact refund for decisions which benefited them for many years, but were "wrong" for a brief time.[167]

Since well before the period at issue both Seattle and Tacoma had over two decades of trading experience in Northwest wholesale markets. Exh. NPG-1 at 17; Exh. ENR-1 at 9. They have large trading operations, and bought and sold millions of kilowatt-hours of electricity in 2000. Exh. NPG-4 at 9; Exh. NPG-16 at 9. Dr. Jones made clear that such entities have many tools available to reduce their exposure to price risk, such as options on forward contracts and financial instruments such as contracts that exchange fixed prices for floating prices and other bilateral instruments. Exh. PPL-1 at 22-23.

---

[166] Dr. Pechman likens their position to that of an emphysema patient who should not be forced to pay high prices for oxygen simply "because he knew or should have known that smoking cigarettes could adversely affect his health," Exh. CAL-14 at 8:5-6, but this hyperbole has nothing to do with the refund claimants' situation. If anything, the refund claimants are akin to *hospitals* that sell oxygen to make a quick profit, gambling that they will not need it or can replace it at a low price. Despite Dr. Pechman's attempt to arouse emotions in their favor, neither his clients nor the other refund claimants have shown why they should not be responsible for their decisions.

[167] *See Entergy Nuclear Indian Point 3 LLC*, 92 FERC ¶ 61,281 at 61,946 (2000) ("[W]e see no evidence that this transaction is not the result of arms' length negotiations. We will not require Applicants to insulate their affiliates' customers from the normal business risk that some ventures may involve greater risk than others."); *OXY USA Inc*., 59 FERC ¶ 61,017 at 61,041 (1992) (Commission refuses to intercede in consensual process by which parties renegotiate contracts upon commencement of market-based rates); *Texas Eastern Transmission Corp*., 55 FERC ¶ 61,482 at 62,603-05 (1991) (rate design that reflects the "consensual allocation of economic risk between the parties" should be implemented unless it is unreasonable because, for example, it was "not the result of an arm's length negotiation," one party was "able to exercise sufficient market power to deprive the customer of a meaningful choice in the matter," or the rate would give one source a "non-market-related, anticompetitive advantage."); s*ee also Tennessee Gas Pipeline Co. v. FERC*, 824 F.2d 78, 82 (D.C Cir. 1987) (noting the "interest in allowing firms to allocate risk among themselves.")

In support of its contentions TFG asserts that refund claimants made no showing that they were subject to any limitation on their ability to hedge their risks as they saw fit. Dr. Cicchetti identified numerous tools that were available, including New York Mercantile Exchange electricity futures at Cinergy, PJM, Palo Verde, and California Oregon Border, Over-the-Counter (OTC) price swaps, and OTC forward products, which are quite varied in terms of specification and contract maturity.

Hedges for spot price volatility existed in the PNW in the form of bilateral forward futures, OTC forward contracts and self-build options. Buyers that wanted to hedge in the PNW could have done so. Exh. IE-2 at 14. NPG witness Ms. Stegeman stated the truism that if options were bought at an unduly high price they might not be beneficial. Exh. NPG-57 at 4. However, Ms Stegeman also agreed that every traditional tool that load-serving entities use to hedge against the risk of variability of price in the spot market, was available throughout the PNW market during the period December 25, 2000 through June 20, 2001. Tr. at 656-657. California Parties' witness Dr. Pechman attempted – without explanation or proof – to dismiss hedging strategies as “nascent economic instruments,” Exh. CAL-14 at 15, but on cross-examination he admitted that hedging products had been available for decades. Tr. at 1033:13-25. Options do, of course, have a cost. Nonetheless, they are a useful tool in reducing exposure to price risk, particularly in volatile markets, such as the PNW spot market during the relevant period. The refund claimants simply elected to forego these means and others to protect themselves from price increases in the spot market. On examination by his own counsel, Port of Seattle witness Holbrook conceded that: “prior to the energy crisis, we probably could have entered into a hedging contract for less than what we're paying today.” Tr. at 627:12-627:19.

As described above, the increase in market prices that began in the late Spring of 2000 reflected market fundamentals – increasing demand at a time of significantly reduced supply. Of course, these higher prices were not initially troublesome to the refund claimants, because power flows in the summer from the PNW to California. Only when higher prices persisted into the Fall did they become an issue for the PNW refund proponents, because that is when flows traditionally reverse so that power flows from California to the PNW. Exh. ENR-1 at 7-8.

TFG further avers that the refund claimants contend that they cannot be expected to have foreseen the market forces that led to the volatility of the spot market during the relevant period. This claim is contrary to the evidence, including the testimony of the claimants’ own witnesses. For example, Ms. Stegeman’s testimony notes the first price spike came in May 2000, natural gas prices started rising in the Summer of 2000, and the Mid-C firm peak index in June was as high as $672.88/MWh. Exh. NPG-16 at 15.

Seattle City Light's witness Mr. McCullough similarly testified that high prices began in May of 2000. Exh. NPG-68 at 6, 11.

The evidence proves that in the Summer of 2000 Seattle and Tacoma, who were then selling wholesale power into the spot market, had noticed that spot market prices were becoming more volatile, at least in part due to supply shortfalls. Another witness supporting refunds, Mr. Hart, testified that "in the summer of 2000, CERS might have been able to secure reasonably priced forward block bilateral arrangements for the Winter and Spring of 2001" had it been in existence then. Exh. CAL-9 at 3. Such forward contracts were available in the marketplace at this time, and Seattle and Tacoma could have increased their forward purchases instead of increasing their reliance on the spot market, TFG maintains.

In short, TFG asserts, the perceived flaws in market structure that led the Commission to direct refunds in the California proceeding are not present here. Moreover, the cure that the Commission prescribed for California is a large forward market and a wide variety of products from which buyers can assemble balanced portfolios that hedge against both delivery and price risks.[168] Precisely these attributes have at all times, including the period at issue here, characterized the PNW market. Rather, refund claimants seek to have the Commission reimburse them for their voluntary choices in a market that offered them many alternatives.

TFG argues that in authorizing sales of power at market-based rates, the Commission has concluded that prices negotiated between sellers and buyers, in the absence of market power, are just and reasonable and, therefore, "lawful." In fact, important public policy considerations have necessitated development of a competitive wholesale electric market over the last decade.

As the United States Supreme Court has noted, "the history of Part II of the Federal Power Act indicates an overriding policy of maintaining competition to the maximum extent possible consistent with the public interest."[169] In response, the

---

168 *See, e.g., San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services into Markets Operated by the California Indep. Sys. Operator and the California Power Exchange*, 92 FERC ¶ 61,172 at 61,607-8 (2000); December 15 Order, 93 FERC at 61,981-82, 61,995, 61,999.

57 *Otter Tail Power Co. v. U.S.*, 401 U.S. 366, 374 (1973); *see also Public Sys. v. FERC*, 606 F.2d 973, 982 (1979) ("On numerous occasions the Supreme Court has

(continued...)

Commission for over a decade has consistently sought to foster the development of the competitive wholesale electric market.[170] In unleashing competitive market forces, the Commission attempted to create a structure that would send timely and accurate price signals to both the supply and demand sides of the market. The Commission's goal was to provide reliable supplies of electricity at the lowest cost to U.S. consumers over the long run.[171] Implicit was the knowledge that prices will fluctuate in a competitive market, at times to extreme levels. Explicit was the belief that, in the long run, lower costs and greater efficiencies would be achieved to the benefit of all.[172]

According to TFG, it is not, therefore, exaggeration to say that the primary public policy goal of the Commission over the last decade has been to foster and protect the development of a wholesale competitive electric market. That goal has not changed despite events in California. In its April 26 Order, the Commission lists certain design principles to guide the development of any market mitigation plan for California:

> [B]uyers and sellers need to know the rules up front and have confidence that those rules will not be subject to constant change or interpretation; prices should be mitigated before they are charged, not after; price mitigation should be as surgical (least intrusive) as possible and last for as little time as possible; price mitigation should be as market oriented as possible and adopt market

---

(...continued)
recognized the importance of competition in regulated industries and the responsibility of regulatory agencies to encourage competitive forces.").

170 Order No. 888 at 31,639-52. In moving away from a heavily regulated cost-of-service regime for wholesale power sales, the Commission, often citing Congressional intent, found that: costs of electric supply were higher than necessary; regulated prices created distorted market signals; stranded costs had been incurred, further distorting market signals; there existed a utility-by-utility, region-by-region disparity of prices; economic and environmental efficiency were not being maximized; and, new technologies developed best under competitive conditions and their development needed to be encouraged. *Id.*; *see also Pub. Svc. Co. of Indiana*, 49 FERC ¶ 61,346 at 62,445-46 (1989).

171 *Pub. Svc. Co. of Indiana*, 49 FERC at 62,243.

172 *Pacific Gas & Elec. Co.*, 38 FERC ¶ 61,242 at 61,792 (1987) ("It is on the basis of efficiency, and the likelihood that increased efficiency will result in lower prices to consumers, that we shall approve the [market-based] rates in the WSPP as just and reasonable.").

> solutions and mechanisms to the maximum extent possible; the pricing provisions must encourage, and not discourage, the critically needed investment in infrastructure (e.g., increasing generation supply, adding required transmission, and implementing demand response).[173]

The TFG submits that these same principles should form the basis for any decision in this case.

TFG avers that there is nothing in the market structure of the PNW which is anti-competitive or which needs to be "corrected." Most of the power is traded in the forward markets, and only a small percentage of the transactions occur in the daily balancing, highly volatile spot market[174] – precisely the model the Commission supports in its orders concerning the California market. The Commission should be most concerned not to destroy the functioning of the PNW markets while it works to remedy what it has determined to be flaws in the California structure.

TFG further maintains that the refunds proponents retreat to cost-of-service pricing or production costs as the basis for their proposed refund determinations. This course is ill-advised and would mangle market price signals. *See* Section IV.C.2 *supra*. It is also at war with the Commission's efforts to nurture the development of competitive market forces. The Commission itself has rejected this approach:

> We reject proposals to return to cost based regulation. . .[P]rices based upon traditional cost of service are incompatible with fostering a competitive market. As we stated in the November 1 Order, traditional cost-based pricing reflects the cost of the asset without any regard to market conditions. The one thing California needs most is new supply and a return to traditional cost of service will not encourage supply to enter the California market.[175]

Further:

> Several commenters suggest that the commission require marginal cost based bids . . . We reject these proposals for numerous reasons . . . In the absence of a capacity market, as is the case in California, if a seller only has peaking

---

173 95 FERC at 61,352.

174 Exh PWX-12 at 5:14-17, 9:6-7

175 December 15 Order, 93 FERC at 62,008.

> units, it would only receive the variable cost of energy and no payment for its fixed cost. Sellers could not stay in business long with that revenue stream.[176]

And finally:

> Market-based rates helped to develop competitive bulk power markets. A generating utility allowed to sell its power at market-based rates could move more quickly to take advantage of short-term or even long-term market opportunities than those laboring under traditional cost-of-service tariffs. . .[177]

Absent compelling reasons to reset prices charged between willing buyers and willing sellers, market pricing should continue to establish just and reasonable rates for the wholesale spot market in the PNW.[178] It is particularly important in this regard that sellers be able to recover the costs of the power that they purchased in the market from third parties. Analysis of any price cap should rest, not on the level of prices in a small portion of the PNW market over a short period of time, but rather on the market structure that produced those prices and rapidly readjusted.

TFG further contends that the record proves that the PNW market, with a long history of trading with multiple buyers, sellers and products, was working in a competitive manner. Tacoma witness Ms. Stegeman admitted that she had no challenge to the conduct of any particular party selling power in the PNW. Tr. at 659. Seattle witness Mr. McCullough stated in his rebuttal testimony that: "The Pacific Northwest market over this time period was a price taker," which means that no entity in the region was able to exercise market power. Other expert witnesses admitted that they had no evidence of market power in the PNW. Philip Movish, witness for Tacoma, Port of Seattle, and Northern Wasco, admitted that there were a substantial number of sellers in the region, particularly in this time period. Tr. at 727. He also admitted that he had not studied how many vendors of wholesale power it would take to ensure a competitive market. Tr. at 732-33. Witness for the California Parties, Dr. Carl Pechman, admitted that he had not provided an economic analysis of demand elasticity in his testimony. Tr.

---

176 *Id*. at 62,008-9.

177 Order 888 at 33,061-62.

178 As will be demonstrated in the ensuing sections, the claimants and the Commission bear a heavy burden of proof to retroactively change prices which have already been determined just and reasonable.

at 1030. Further, he admitted that he had not provided any evidence of "joint action," by PNW power suppliers. Tr. at 1030.

In sum, TFG argues, there is not even one specific allegation in the entire record of the existence or exercise of market power or violation of any tariff or agreement.

2a. What Was The Volume Of Spot Market Bilateral Sales Transactions In The Pacific Northwest For The Period December 25, 2000 Through June 20, 2001?

2b. What Were The Price And Terms And Conditions Of The Sales Contracts For Spot Market Bilateral Sales Transactions In The Pacific Northwest For The Period December 25, 2000 Through June 20, 2001?

2c. Who Were The Net Sellers And Net Buyers Of Electric Energy In Spot Market Bilateral Sales Transactions In The Pacific Northwest For The Period December 25, 2000 Through June 20, 2001?

NPG:

Data regarding the three above issues, *i.e.*, the volume of sales transactions, the prices, terms, and conditions of sale, and the identity of net sellers and net buyers has been submitted by many, but not all, Pacific Northwest market participants in the form of responses to a data template prepared by Commission staff and adopted by the Presiding Judge, NPG maintains. This information has been submitted *in camera* and has not been available for use by any other than the party submitting the data.

NPG argues it can neither verify nor validate whether the sellers submitted data sufficient for the Commission to determine the price, terms and conditions of every spot market sales transaction in the Pacific Northwest from December 25, 2000 through June 20, 2001. Pursuant to the August 9 and 13 Orders in this proceeding, data was submitted to the Presiding Judge and to Commission staff under seal. Such data is not available for public review. Thus, the sellers' identities, and the reported prices, terms and conditions of spot market sales transactions in the Pacific Northwest for the period December 25, 2000 through June 20, 2001, have not been tested by counterparties to those transactions – the purchasers who paid the unjust and unreasonable prices. The Commission itself must examine the sealed data submissions in this proceeding to determine the prices and terms and conditions of the spot market bilateral sales transactions in the Pacific Northwest for the period December 25, 2000 through June 20, 2001.

CALIFORNIA PARTIES:

California Parties contend that the confidential template data assembled by Commission Staff, based on submissions from all transaction participants, will provide the total volume of spot market bilateral sales transactions in the PNW for the period December 25, 2000 through June 20, 2001. The California Parties have answered the same question concerning transactions involving CERS through evidence at hearing.

In the PNW, CERS purchased a total volume of 6,803,549 MW/h during the refund period, at a cost of $2,638,589,077, for an average cost of $388 per MW/h. (CAL-11). In addition, CERS engaged in exchanges in the amount of 584,725 MW/h. (CAL-12). Finally, CERS made sales during the refund period in the amount of 67,117 MW/h, for which it charged $1,606,689 (i.e., an average sales rate of $24 MW/h). (CAL-13).

According to the California Parties, during the refund period, CERS purchased 1,942,581 MW/h from Powerex on a 24 hour-or-less basis at a total cost of $898,267,499, for an average rate of $462 MW/h. (CAL-11). Powerex contends that virtually all of these 24 hour-or-less sales must be excluded for refund purposes because they do not constitute "spot market" sales. (Peterson, PWX-6 at 11:2-4). Powerex's theory for exclusion is that these sales were made under a "capacity-backed fixed-price arrangement" that was negotiated between Powerex and CERS "at the most senior level." (Peterson, PWX-6 at 10-11). The facts do not support this claim, California Parties argue. During the refund period, CERS made a series of purchases from Powerex of 24 hours or less in duration on a last-resort basis, and Powerex charged whatever it wanted to charge for the power -- often $500 MW/h -- because it was able to do so.[179] In a bilateral market, all of the transaction prices were based upon the offers made by sellers. Moreover, as California Parties' Witness Hart explained on rebuttal, there was no "contract" to provide variable quantities at a fixed price; this was a series of transactions entered on a daily or hourly basis at whatever price Powerex demanded. (CAL-9 at 4:13-21).

California Parties contend that nowhere in the testimony of Powerex's witnesses or on cross-examination was Powerex able to elicit any evidence that confirms an agreement between Powerex and CERS that sales by Powerex would be either

179 Witness Hart explained on cross-examination: "Basically . . . Powerex unilaterally set its prices on any given moment of every day, and periodically I would call them saying look, you guys continue to charge us prices that are way out of the market. You need to bring them down. . . . I continually asked them for forward purchase contracts. I never got them. All I ever got was spot purchases at the price they dictated." (Tr. 897:17-25 - 898:1).

"capacity-backed" or "fixed-price." Powerex has produced no agreement that either (1) obligated Powerex to sell any particular quantities to CERS at any particular price, or even to stand ready to do so, or (2) obligated CERS to purchase particular quantities or to purchase quantities on demand at a particular price. The only written agreements produced by Powerex, TFG-17 and 18, were created for the sole purpose of modifying the standard WSPP purchase agreement[180] credit and payment terms. Those modifications essentially provided that, in the event Powerex and CERS happened to enter into bilateral transactions during the specified time periods, special (i.e., far more stringent) credit and payment terms would apply. The *only* reference to price or volumes in TFG-17 and 18 is a *disclaimer* concerning those items -- a representation that the agreements specifically do *not* address price and volumes, and that any arrangements concerning price and volumes must be made "in the normal course" pursuant to verbal confirmations between the respective trading personnel of Powerex and CERS.[181] For all of the transactions at issue that Powerex seeks to exclude, these verbal confirmations "confirmed" a transaction of 24 hours or less.[182]

180

Exhibit 6.

181

Thus, Preamble Paragraph D of TFG-17 provides:

> Powerex and CDWR also understand and intend that **verbal confirmations as to price and volumes will be made in the normal course between** their respective trading personnel and that this Confirmation Agreement will apply to such transactions and that **no obligation to deliver energy arises hereunder other than pursuant to such verbal confirmations.**
>
> TFG-17: 2 (emphasis added). An identical provision is contained in TFG-18, Preamble Paragraph D:1.

182

If Powerex were correct that it had a long-term "capacity-backed" "fixed-price" contract with CERS, the WSPP Purchase Agreement would have required the terms to be set forth in writing in a Confirmation Agreement. Section 32.1 of the WSPP Agreement specifies that: "Written confirmation shall be required for all transactions of one week or more." According to Powerex, its "capacity-backed" "fixed-price" agreement with CERS was in place from January 17, 2001 through June 20, 2001, yet, in violation of Section 32.1 of the WSPP Agreement, neither of these alleged essential terms was ever confirmed in writing. This is further evidence that no such agreement existed.

(continued...)

The testimony of the TFG experts on the definition of "spot market" transactions is singularly unhelpful to Powerex on this issue, California Parties maintain. Mr. Adamson, for example, identified the key concept in spot market transactions as "immediacy." (ENR-25 at 4-5). Plainly, CERS' purchases from Powerex on a daily and hourly basis were "immediate" within Mr. Adamson's definition. Recognizing the possibility of sales by Powerex to CERS, the parties agreed in TFG-17 and 18, at the insistence of Powerex, to modify the WSPP credit and payment arrangements that otherwise would govern transactions of 24 hours or less. The sales themselves, however, occurred on a purely last-minute 24 hours-or-less basis at whatever price Powerex dictated.

Similarly, TFG Witness Van Vactor highlighted as a hallmark of spot market transactions that there be no obligation or implied intent to continue to sell in subsequent periods. (ENR-23 at 4:18-19). Applied here, this criterion necessarily results in a determination that Powerex's sales to CERS were spot market transactions within Mr. Van Vactor's definition: as set forth in TFG-17 and 18, Powerex had no obligation to CERS beyond the day-to-day verbal confirmations between traders. Moreover, as explained by Mr. Hart, CERS did not purchase from Powerex on a daily basis unless it had no other choice.[183]

Powerex's own expert, Dr. Tabors, offered no credible support for Powerex's claim on this point. As revealed in both his rebuttal testimony (PWX-12 at 8) and in cross-examination (Tr. 993-994), Dr. Tabors relied exclusively on characterizations about the so-called arrangement provided to him by Powerex's Witnesses Peterson and Yazdi. Dr. Tabors was unable to offer any independent assessment of whether the vast number of daily transactions that Powerex seeks to exclude were spot market transactions

---

(...continued)

183

As Mr. Hart explained in his testimony:

> Indeed, our purchases from Powerex were usually our last purchases, because Powerex's price was usually the highest. It was Powerex's choice to sell to us in this last-minute fashion, and there is no useful distinction between the types of transactions we entered into with Powerex, and all of the other sport market transactions in which CERS engaged, except that we generally had to pay a lot more to Powerex under extreme payment schedules to satisfy credit concerns.
>
> (CAL-9 at 4:19 - 5:2).

or otherwise.[184] Attempting to offer "circumstantial" evidence of a fixed-price agreement between Powerex and CERS for purchases at $500 MW/h, Powerex enlisted Dr. Tabors to graph the pricing of the transactions between Powerex and CERS during the refund period. (TFG-20). Notwithstanding the numerous errors of omission and inclusion,[185] the graph, however, reveals nothing more than the fact that CERS paid Powerex the exorbitant price of $500 MW/h for numerous individual transactions of 24 hours or less during the refund period.[186]

184

As Dr. Tabors testified on cross-examination:

Q. Now, you referred to the agreement between Powerex and CERS. There isn't any agreement, is there? There's no contract?
A. There's an agreement that was referenced in other testimony, not mine.
Q. Have you seen the contract that you're referring to now, the contract that you said was for a fixed price agreement . . . ?
A. Have I seen that? No, sir.
Tr. 993:23 - 994:4.

185

Data in Mr. Green's work papers (TFG-19) that does not appear to be reflected on TFG-20 includes the following: 3/12/01 ($370); 5/2/01 ($194); 5/4/01 ($105); 5/5/01 ($105); 5/18/01 ($84); 5/19/01 ($84); 5/30/01 ($69); 6/1/01 ($111); 6/2/01 ($111); 6/3/01 ($135); and 6/5/01 ($81).

Data points on TFG-20 that do not appear in Mr. Green's underlying work papers (TFG-19) include the following: 1/17/01 ($600); 1/17/01 ($480); 1/17/01 ($445); 3/12/01 ($340); 3/26/01 ($375); 3/26/01 ($250); 3/26/01 ($100); 4/12/01 ($0); 5/4/01 ($194); 5/5/01 ($194); 5/5/01 ($175); 5/6/01 ($194); 5/19/01 ($0); 5/21/01 ($0); 6/15/01 ($325); 6/16/01 (290); 6/17/01 ($500); and 6/17/01 ($450).

Given that Dr. Tabors "checked this data over a number of times" (Tr. 993:10), the sheer quantity of errors raises legitimate concerns about the reliability of Dr. Tabors' testimony generally.

186

TFG-20 purports to be a graphic depiction of Mr. Green's work papers introduced into the record by Powerex as TFG-19. As a comparison between those work papers in TFG-19 and Dr. Tabors' graph demonstrates, there are numerous dates on which the graph reports the price charged as $500 MW/h, but the actual price reported in the work papers was not $500 MW/h: 1/25/01 ($498); 1/26/01 ($498); 2/13/01 ($497); 2/14/01 ($497); 2/15/01 ($497); 2/16/01 ($497); 2/17/01 ($497); 2/18/01 ($497); 2/19/01 ($497); 2/20/01 ($497); 2/21/01

(continued...)

Even less helpful to Powerex on this issue is a Commission Staff Report used by TFG in an attempt to impeach Commission Staff Witness Tingle-Stewart, wherein Commission Staff defined a "forward" contract (i.e., the type of contract that Powerex claims it had with CERS) as one in which the buyer "is obligated to take delivery" and the seller is "obligated to provide delivery" of a "fixed amount of a commodity" at a "predetermined price" on a "specified future date."[187] The alleged "forward" agreement between Powerex and CERS fails each of these specific tests.[188]

In summary, according to the California Parties, the numerous daily and hourly transactions between Powerex and CERS during the refund period are precisely what they appear to be -- daily and hourly transactions that qualify as "spot market" transactions under even the most narrow definition of that term as advocated by Powerex and the other TFG group members.[189] The facts indicate that Powerex exercised raw economic power over CERS in a series of hourly and daily transactions. There was no

---

(...continued)
($497); 2/22/01 ($497); 2/23/01 ($397); 2/26/01 ($497); and 2/27/01 ($497).

187 TFG-26 (Staff Report dated September 22, 1998, Section G-2, definition of "forward contract").

188 Powerex suggested on cross-examination that its sales to CERS constituted a "forward contract" (i.e., in its view something other than an includable spot market contract) because Section 35 of the WSPP agreement provides that transactions under the WSPP Agreement are "forward contracts" for purposes of the United States Bankruptcy Code. (Tr. 889:8-891:6). Not so. For Bankruptcy Code purposes, the "forward contract" designation simply means that various Bankruptcy Code provisions that could otherwise disrupt commodities markets, such as the automatic stay and the trustee's avoidance powers, do not apply. 3 Collier on Bankruptcy (15th Ed.). ¶ 362.05[6]. The WSPP Agreement's incorporation of this Bankruptcy Code protective device obviously does not transform transactions that are one hour real time spot market sales into long-term forward contracts.

189 Of course, if one of the broader definitions of "spot market" advocated either by the claimants or by Commission Staff is adopted, all of the transactions in question that Powerex erroneously attempts to characterize as 'forward" transactions nonetheless would be included as "spot market" transactions, because they occurred over a period of less than a year (indeed, approximately 5 months).

contract. Powerex did not offer a "unique product" based on high-level negotiations." (Yazdi, PWX-7A at 7:6-10). CERS bought from Powerex on a daily and hourly basis (but only what it needed to buy after exhausting other lower-cost sources), and paid whatever Powerex demanded. As California Parties' Witness Hart explained, CERS would have preferred a forward contract with Powerex, but Powerex consistently refused to enter into such an arrangement (CAL-9 at 4:1-5; Tr. 897:17 - 898:1).

Certain parties, including BPA and Powerex, maintain that where the seller acted merely as an intermediary or agent for the buyer in purchasing power from other sellers and reselling to CERS, such transactions must be excluded from the refund calculation. (Oliver Direct, BPA-1 at 13-14; Yazdi, PWX-7A at 9-10). BPA refers to these types of transactions as "sleeve" transactions, whereas Powerex refers to them as "aggregation service." Both argue, for different reasons, that these types of transactions are not includable spot market bilateral transactions. Neither is correct.

With respect to the "sleeve" transactions described by BPA, the reasons given for exclusion are purely equitable in nature, in that they focus on the motivation for the transaction and the margin (or lack thereof) earned by BPA. (Oliver Direct, BPA-1 at 13-14). The California Parties acknowledge that equitable considerations may be germane to a determination of whether a refund is appropriate. Analytically, however, equitable considerations have nothing to do with whether a particular transaction is includable as a spot market bilateral sales transaction in this proceeding. In the "sleeve" transactions discussed by BPA, BPA indisputably is the seller of record. Assuming that the transactions otherwise qualify as spot market transactions -- and BPA does not allege otherwise -- they cannot be excluded merely because BPA may have undertaken the transaction to assist CERS at minimal compensation, as BPA claims.

With respect to the "aggregation service" provided by Powerex, the same analytical approach compels the conclusion that the transactions should be included as spot market bilateral transactions, so long as they otherwise qualify as such. Powerex argues that they do not so qualify, because Powerex made these sales as part of a "continuing arrangement." (Yazdi, PWX-7A at 10:4-7). As with its alleged "capacity-backed fixed-price" contract discussed above, Powerex offers no proof of a "continuing arrangement" as to these transactions. As explained by California Parties' Witness Hart, these were *daily* transactions in which Powerex acted as a marketer for profit.[190] On the present record, there is no basis for excluding either BPA's "sleeve"

---

190 As Mr. Hart explained in rebuttal:

(continued...)

transactions or Powerex's "aggregation service" transactions. Both parties were the sellers of record in these transactions. The transactions occurred on an hourly or daily basis, so they qualify as "spot market" transactions under even the most narrow definition advocated by TFG. Neither party has provided a rational or credible basis for treating the transactions as other than spot market bilateral transactions.[191]

During the refund period, CERS entered into exchange transactions with BPA and Powerex, for a total volume of 584,725 MW/h. (CAL-12). A typical exchange, the sending and receiving of products, is one in which one party, such as CERS, sends energy to a counter-party before Summer for return during the Summer. (Green Direct, CAL-1 at 5:1-3). In the Order on Format for Data Submission,[192] parties were invited to treat exchange transactions as transactions subject to refund and to submit relevant data.

BPA attacks the basic theory of including exchanges, arguing that the transactions do not involve a dollar per MW/h rate. (Oliver Direct, BPA-1 at 16:3-6). As California Parties' Witness Green explained on rebuttal, however, exchange transactions are appropriate for inclusion because they were a substitute for purchases, at an exchange

(...continued)

> Beginning in early May of 2001, CERS used Powerex as an aggregator for daily purchases at the mid-Columbia hub for delivery to the California-Oregon Border ("COB") and the Nevada-Oregon Border ("NOB"). Powerex essentially acted as a marketer in these daily transactions, and charged the mid-Columbia index price plus a percentage mark-up determined by Powerex. Powerex then was responsible for all transmission charges and losses incurred in transporting the power to CERS. Powerex insisted on doing this in order to give CERS firm energy delivered at a point and price. It was no different from any other short term transaction.
> (CAL-9 at 8:12-19).

191 The same rationale applies to IDACORP witness Ciccheti's claim that marketers should not be required to pay refunds. (IE-2 at 26). If a marketer is the seller of record, the transaction must be includable for refund purposes, just as any other seller's transaction is included.

192 Order on Format for Data Submissions, issued August 9, 2001, slip op. at 10 ("There will not be an exchange template. Parties claiming a refund for an exchange transaction shall file the relevant data for the transaction, specifying this fact.").

rate that produced a MW/h value significantly higher than a reasonable purchase price. (CAL-10 at 8:23 - 9:2), the California Parties argue.

According to the California Parties, Powerex argues that the two exchange transactions in which it engaged with CERS should be excluded because (1) they are seasonal in nature and thus have no nexus to spot market transactions, and (2) the "returns" by Powerex of energy provided by CERS to Powerex during the refund period will not occur until after the close of the refund period. (Yazdi, PWX-7A at 12:1-5; Tr. 939-940). Neither argument has merit. The first argument -- concerning the seasonal nature of exchanges -- precludes recovery only if Your Honor and the Commission adopt the extremely narrow "24 hours or less" definition of "spot market" urged by Powerex and the other TFG group members.[193] As for Powerex's second objection -- that the redelivery period falls outside of the refund period -- the short answer is the one provided by Mr. Green on cross-examination: CERS performed its part of the bargain -- that is, it already "paid" by providing power to Powerex -- during the refund period; when Powerex returns the power, it should do so at a reasonable (i.e., mitigated) equivalent price. (Tr. 939-940).

The California Parties -- the AG , the PUC and the EOB -- are seeking refunds in this case on behalf of California ratepayers for whom CERS purchased power during the refund period. CERS was required to pay exorbitant rates for power during the refund period, in order to meet the energy needs of California consumers, and California consumers will continue to bear the brunt of those high prices. CERS, a net buyer of electric energy in the PNW during the refund period, has not asserted a refund claim on its own behalf that is separate from the claim presented by the California Parties. Rather, the refund claim associated with CERS' refund period purchases, the proceeds of which, under California law, will be flowed back to California's consumers, is being asserted by the California Parties, the lawful representatives of California's retail ratepayers. The California Parties have standing to assert the refund claim of retail ratepayers associated with CERS' purchases on behalf of those ratepayers. The FPA specifically authorizes the Commission to admit as a party in a proceeding "any representative of interested

193

Even this argument does not apply to power delivered by CERS to Powerex during the period May 18 - May 21. See TFG-22. That time period encompassed a Friday and a three day weekend (May 21, 2001 was a Canadian holiday), and therefore fits within even TFG's definition that includes the Pacific Northwest "24 hours or less" spot market weekend convention. (See e.g., Tr. 903:16 - 904: 3).

consumers."[194] Interpreting a similar provision in the Natural Gas Act, the D.C. Circuit explained that the consumer representative in such situations need not have the interest of a direct purchaser, but instead relies on the interest of the state in protecting its citizens -- that is, the state's *parens patriae* interest.[195] Similarly, the Commission traditionally has permitted state consumer representatives automatic party status in proceedings,[196] and has permitted states' attorneys general, state commissions and other state agencies that represent consumer interests standing to litigate wholesale rate issues.[197]

Importantly, the California Parties maintain, in recognizing the standing of state agencies to litigate wholesale rates, the Commission has made it quite clear that the indirect claim of a state agency on behalf of retail consumers is distinct from and not in any way dependent upon the participation or non-participation of the direct purchasers who serve those same end user retail customers. Thus, in *United Gas Pipe Line Co.*,[198] the Commission

---

194 Section 308 of the FPA, 16 U.S.C. § 825g(a).

195 *Maryland People's Counsel v. FERC*, 760 F.2d 318, 321 (D.C. Circ. 1985) ("It seems to us inconceivable that the specific provision of party . . . status for states and state agencies envisioned that these entities would be particularly likely purchasers of natural gas; to the contrary, it was evidently designed to recognize precisely the interest of the states in protecting their citizens in this traditional governmental field of utility regulation -- that is, the states' *parens patriae* interest.").

196 18 C.F.R. § 385.214(a)(2) ("Any State Commission is a party to any proceeding upon filing a notice of intervention in that proceeding, if the notice is filed within the period established under Rule 210(b)").

197 *Williams Gas Pipelines Central, Inc.*, 94 FERC ¶ 61,285 (2001) (Missouri Public Service Commission permitted to intervene in enforcement action under Natural Gas Act because pipeline was major supplier of natural gas transmission and storage service to Missouri customers, and Missouri Public Service Commission, as public representative of retail consumers in Missouri, was permitted to intervene); *New England Power Co.*, 51 FERC ¶ 61,219 (1990) (Attorney General of Commonwealth of Massachusetts and New Hampshire Public Utilities Commission permitted to intervene out of time in electric rate proceeding, given, *inter alia*, "the interests of the constituencies they represent. . . .").

198

(continued...)

held that state agencies were permitted to pursue litigation on behalf of indirect consumer interests, even though the local gas distribution company -- the actual direct purchaser -- chose not to do so:The Commission recognizes that as a matter of policy LDCs should be able to make their own business judgments and incur the cost consequences that result. LDCs may not want to litigate, and the Commission under Order No. 500 generally discourages litigation. However, it also must be recognized that state regulatory agencies have legitimate interests in having an opportunity to litigate the wholesale rates. In weighing these interests, the Commission chose to recognize the state agencies' interest in being able to litigate. *This is consistent with our long standing practice of recognizing the standing of state agencies to litigate wholesale rates.*[199]

The essential teaching of *United Gas Pipe Line*, therefore, is that state consumer representatives may pursue an indirect claim on behalf of consumers (and may be the party best suited to do so) even though the direct purchaser from the regulated seller chooses not to pursue a claim. Each of the California Parties -- the AG ,[200] the PUC,[201] and the EOB,[202] -- has authority under California law to act on behalf of California's retail ratepayers. Any refunds awarded in this case associated with CERS' purchases on behalf of California's

(...continued)
45 FERC ¶ 61,335 (1988).

199

45 FERC ¶ 61,335 at 62,054 (emphasis supplied).

200

Under the California Constitution and the California Government Code, the Attorney General is authorized to safeguard the public interest, which includes the authority to represent the interests of California's retail end use customers, who are entitled to refunds associated with wholesale electric power purchases made by CERS on their behalf. Cal.Const. art. V, § 13; Cal.Govt.Code § 12511.

201

The California Public Utilities Commission is a constitutionally-established agency with the statutory mandate to represent the interests of natural gas and electric consumers throughout California in proceedings before this Commission. Cal.Pub.Util.Code § 307. In addition, the CPUC is directed to "participate fully in all proceedings before this Commission in connection with" electric restructuring in California. Cal.Pub.Util.Code § 365.

202

The Electricity Oversight Board is authorized by statute to represent the state of California and its citizens in litigation before this Commission. Cal.Pub.Util.Code § 341.

retail end use customers will, as a matter of California law, accrue to the benefit of retail ratepayers. CERS operates under the provisions of ABX1-1, enacted February 1, 2001.[203] Among other things, the statute establishes the Department of Water Resources Electric Power Fund, and requires that all revenues payable to CERS under the statute be deposited in that Fund. CERS may sell power acquired under the statute to retail end use customers, *at not more than its acquisition costs*, including related costs of transmission, scheduling, etc. Payments from the fund may be made only for purposes authorized by the statute. Accordingly, any refunds paid to CERS will be deposited in the first instance in the Electric Power Fund, but then will flow back to retail end use customers in order to satisfy the statute's requirement that CERS charge those end use customers no more than its acquisition costs for power. going to the retail end user less costs.

According to the California Parties, the Commission has determined in a series of recent orders in this and the *San Diego* proceeding, that it may exercise conditional authority over municipal utilities and other public power entities (collectively, "non-public utilities"), and that it may order refunds to be paid by non-public utilities. In addition, the Commission clearly set the scope of this proceeding to determine issues related to *all* sales made in the PNW , with no exemption for sales made by non-public utilities.

NON-JURISDICTIONAL UTILITIES:

Non-jurisdictional municipal utilities have asserted throughout this proceeding that it is unlawful to order refunds related to the bilateral power sales of non-public utilities in the Pacific Northwest for the period in question. According to these entities, the jurisdictional reasoning that underlies the assertion of refund authority over power sales of non-public utilities to the California Independent System Operator and Power Exchange markets in the Commission's Order of July 25, in Docket No. EL00-95, *et al*., may not extend to the bilateral power sales of non-public utilities in the Pacific Northwest market for the bilateral power sales of non-public utilities in the Pacific Northwest market for the period in question in this proceeding. A centralized single clearing price auction that sets wholesale prices for both public utilities and non-public utilities, pursuant to market rules set by this Commission and administered by public utilities subject to the Commission's jurisdiction (the California ISO and PX) were the reasons for extending refund authority to certain non-jurisdictional entities that have sold power to the California ISO and PX. These entities argue that the record evidence in this

---

203 AB1x-1 added Division 27 to the California Water Code, §§ 80000-80270. This statute was introduced into the record in this case as TFG-14.

proceeding shows that the circumstances in the Pacific Northwest bear no resemblance to the sales in the California ISO/PX. For instance, the sales at issue were made pursuant to bilateral contracts voluntarily entered into between willing buyers and willing sellers. The Pacific Northwest operates as a true commodity market where prices are set by bilateral negotiation, rather than administered by a separate authority. Ex. NPG-1 at 7, 11. The Northwest market is largely the product of the existence of the regional non-jurisdictional transmission system and the Northwest's hydroelectric generation base. In addition, these entities maintain the WSPP Agreement specifically states that it does not provide a basis for exercise of Commission jurisdiction over the power sales of utilities such as Municipal Systems and the Commission has stated that it lacks jurisdiction over the bilateral sales of non-jurisdictional entities under the WSPP. *Citing Western Systems Power Pool,* 55 FERC ¶ 61, 495 at 62,713 (1991). The municipal entities further contend that the Commission has no jurisdiction under Section 205 and 206 of the FPA over the power sales of utilities such as municipal systems. *Citing Mid-Continent Area Power Pool ("MAPP")* 89 FERC ¶ 61,135 (1999), reh'g denied, 92 FERC ¶ 61,229 (2000); *New West Energy Corporation,* 83 FERC ¶ 61,004 (1998).

TFG:

TFG avers that volumetric data has been submitted to the Presiding Judge and Staff under confidential seal. [204] Nonetheless it is clear that spot market bilateral sales

---

[204] The statistical data sought was submitted to the ALJ on a confidential basis and presumably will be certified to the Commission. Staff witness Poffenberger, however, provided a glimpse into the breadth and informational value of those submissions and, in the process, underscored numerous problems with this data gathering effort (Exh. S-3 at 6:3-19; Exh. PWX-12 at 2):

- Only 56 of the 220 entities that belong to the WSPP submitted data.

- None of the parties proposing refunds in this case, provided the date and hour when each transaction was entered into. (As noted by Dr. Tabors, Exh. PWX-12 at 3 n.1, and pursuant to the Stipulation entered during the hearing, EWEB does not appear to be seeking affirmative relief, but it did provide dates and hours.)

- The data submitted fails to reveal whether the power purchased was used to serve retail load in the Pacific Northwest or whether is was resold, possibly into California. (Testimony indicates, however, that this information in fact is available. Exh. PGE-1

(continued...)

transactions constituted only a small percentage of the total volume of transactions in the region because forward contracts were heavily relied upon.

Spot market bilateral sales in the PNW took place under diverse prices, terms and conditions, TFG contends. Certain of this information is contained in the confidential data submission.[205]

Moreover, TFG argues most market participants were both buyers and sellers, often in multiple "ripple" transactions. Calculations to determine net positions were not possible, given the available information, time and procedures.[206] Kaiser and Bonneville argue that sales made by Bonneville for Kaiser cannot be undone due to the inequities of ordering the aluminum company to refund money.

STAFF:

According to Staff, in the July 25 order, the Commission noted the "complexities associated with these retroactive bilateral calculations" and established a separate preliminary evidentiary proceeding to facilitate development of a factual record on whether there may have been unjust and unreasonable charges for spot market bilateral sales in the PNW for the period beginning December 25, 2000 through June 20, 2001. The Commission stated that:

> The record should establish the volume of the transactions, the identification of the net sellers and net buyers, the price and terms and conditions of the sales contracts, and the extent of potential refunds. This will help the Commission to

(...continued)
at 3:4-4:2.)

- Sellers that submitted data were unable to identify upstream vendors and it is therefore impossible to fully assess the potential magnitude of so-called "ripple" claims.

What is clear is that the refund claimants represent an extraordinarily small segment of the Pacific Northwest market.

205 *See id.*

206 *See id.*

> determine the extent to which the dysfunctions in the California markets may have affected decisions in the Pacific Northwest. [207]

The Commission required the parties to provide this data to the Presiding Judge no later than 15 days after the first prehearing conference.

At the prehearing conference on August 1, 2001, the parties agreed to submit data on a generic template to be drafted by the Staff. [208] Following Staff's filing of a proposed template and the parties' comments, the Presiding Judge issued orders adopting a template and ordered all parties in the proceeding to provide data. [209] *See* Ex. S-5. [210] The template excludes any transactions made pursuant to orders issued by the Secretary of Energy under § 202(c) of the Federal Power Act or any transactions with the California ISO or the California PX. The template requires only sellers to submit data, consistent with the information submitted in quarterly reports filed at FERC by the WSPP. [211] However, where a buyer's seller did not submit data, a buyer was allowed to do so. [212] All transactions which originated, were delivered or must be transmitted in the PNW were to be reported.

---

[207]96 FERC at 61,520.

[208]On August 3, 2001, Staff submitted its recommended format for reporting hourly sales into the PNW.

[209]"Order on Format for Data Submissions" issued August 9, 2001 and "Order on Motions for Clarification and Request for Modification" issued August 13, 2001.

[210]The template includes columns for: (1) the date and hour that sales begin and end, and the date and hour that the sales transaction was entered into; (2) Upstream Vendor, the Seller's source of supply (purchase or generation) used to make the sale; (3) the name of the Buyer who is purchasing from the Seller; (4) the MWh sales volume; (5) the contract or service schedule that the Seller and Buyer are transacting under; (6) the hourly price of the sale; (7) the hourly revenue from the sale; (8) the point of delivery and (9) the California Independent System Operator's Market Clearing Price (MCP) for that hour, as determined in Docket Nos. EL00-95-045, *et al.* Ex. S-3 at 5.

[211]Staff's recommended format at page 1, filed August 3, 2001.

[212]August 9, 2001 Order at 9.

Beginning on August 16, 2001, the parties began to submit data. However, as detailed in the testimony of Staff witness Poffenberger, the data submitted is incomplete. In terms of the volumes of spot market bilateral transactions, it is not apparent that all entities who may have sold into the PNW market during the relevant time period submitted data. While there are approximately 220 members of the WSPP, only 56 entities responded to the order by either providing data (more than 40 entities) or indicating they had no eligible transactions. Ex. S-4. Thus, there is no indication from approximately 75 percent of WSPP members of whether they participated in the PNW spot market during the relevant time period.

In order to determine which WSPP members did not submit transaction data and obtain a more accurate number of total volumes and transactions, it would be necessary to reconcile the names of those sellers listed in the FERC Form No. 1 for each investor-owned utility located in the PNW with the list of those entities submitting transaction data in this proceeding. Ex. S-3 at 8-9. To cite one example, Idaho Power Company's (Idaho Power) 2000 FERC Form No. 1, pages 326.5 through 326.17, indicates that Idaho Power purchased power from numerous sellers pursuant to the WSPP Agreement. See Ex. S-7. Sellers listed in Idaho Power's FERC Form No.1 could be compared to the list of entities that submitted transaction data in Ex. S-4 to determine which sellers did not submit spot market sales data in this proceeding. For example, Idaho Power's FERC Form No.1 purchased power data indicate that Idaho Power purchased energy from Reliant Energy Services (Reliant) pursuant to the WSPP Agreement during 2000, but Reliant did not submit transaction data in this proceeding. Such additional information would have to be obtained to determine whether the energy sale from Reliant to Idaho Power was a spot market sale in the PNW and whether it occurred between December 25, 2000 and June 20, 2001. This process would have to be repeated for all investor-owned utilities in the PNW. The time constraints of the instant proceeding, however, did not allow for such further discovery. Thus, the volumes and transactions described in the data submissions made August 16, 2001 and later probably understate the actual numbers involved.

In addition to an incomplete list of sellers and transactions, there are a number of problems with the data that was submitted. Certain sellers were unable to identify a specific upstream vendor because the sales were made from a portfolio of resources which may include both generation and purchase contracts. Ex. S-3 at 6. Should the Commission determine that refunds are owed in this proceeding, it will likely be necessary to undo those portfolios to determine the upstream vendor(s).

More significantly, since the seller, not the buyer, submitted the information, it is not possible to tell whether the power was used to serve the buyer's load in the PNW or was resold again, perhaps into California. Ex. S-3 at 6. The template shows delivery points not only within the PNW region but also at border points such as COB and NOB. Further, it cannot be determined from the data submissions which transactions included power that originated or was transmitted through the PNW. Ex. S-3 at 7.

The template requested information about the contract schedule and terms and conditions. Most of the responses to the data template indicate that the majority of the sales transactions were made pursuant to the WSPP agreement. Ex. S-6. The remainder were made pursuant to the Seller's market-based rate electric tariffs on file with the Commission or specific bilateral contracts with the buyer. Ex. S-3 at 7.

The WSPP Agreement is a standardized power sales contract that applies to transactions between its 220 members. WSPP members are allowed to sell at market prices if they have received market-based rate authority from the Commission or if they are not regulated by FERC. The three basic products that are available under the WSPP Agreement are set forth in service schedules. Service Schedule A is Economy Energy Service, which is energy that may be interrupted upon notification to the buyer. Service Schedule B is Unit Commitment Service, which is a sale from a specified generating unit for a specified period of time. Service Schedule C is Firm Capacity/Energy Sale or Exchange Service, which provides for firm capacity transactions with or without associated energy, firm energy transactions, and exchanges of firm capacity and/or energy. The WSPP Agreement provides that Parties are free to negotiate the specific terms and conditions of a transaction under the service schedules. Ex. S-3 at 8.

A very preliminary review of the data submissions indicates a range of prices for some parties. For transactions greater than one month, one claimant paid prices ranging from $165 to $390 for energy. During the month of January 2001, another claimant paid between $115 and $581 for energy during the peak period. As discussed in section 2-f, there is some evidence that one party charged a consistent rate at the higher end of this range over a period of three months (January-March 2001).

Staff avers that whether an entity turns out to have been a net buyer or a net seller of electric energy will depend upon the definition of "spot market" in the PNW.

The data template approved by the Presiding Judge provides for transactions to be grouped in four categories:

- transactions of 24 hours or less

- transactions greater than 24 hours and up to one week

- transactions greater than one week and up to one month

- transactions greater than one month and up to one year

With respect to whether a respondent is a net buyer or net seller, each category will likely produce a different outcome.

2d. What Is The Appropriate Methodology For Determining A Just And Reasonable Rate For Transactions That Occurred In The Bilateral Spot Market In The Pacific Northwest During The Relevant Period?

NPG:

The Commission did not direct the Presiding Judge to determine the appropriate methodology for determining the just and reasonable or “benchmark” price for Pacific Northwest spot market sales during the refund period. Obviously, however, it is necessary to utilize a benchmark price in order to determine the “extent of potential refunds.” While the NPG members used different methodologies for determining the benchmark price, they are based on the marginal costs of Pacific Northwest resources. Many issues relating to the appropriate methodology for determining the just and reasonable price are now before the Commission, and the Commission has indicated that it will be addressing these issues in a further order to be issued by October 15, 2001.[213] For the purpose of this preliminary evidentiary hearing, it is clear from the evidence in the record that, whatever methodology is used to determine the benchmark price, [NPG argues] the “extent of the potential refunds” is substantial.

Seattle City Light believes that the just and reasonable or “benchmark” price for use in determining the extent of the potential refunds in this proceeding should be the marginal cost of the highest cost resource that would have been dispatched to serve load in the Pacific Northwest absent the distortion in the market clearing prices in the California PX and ISO spot markets.

Mr. McCullough determined the monthly benchmark prices by first determining the actual loads during the refund period for the U.S. Northwest Power Pool

[213] *See* “Order Granting Rehearing for Further Consideration,” issued August 30, 2001, in *San Diego Gas & Electric Co.*

("NWPP").[214] He identified the portion of those loads that in fact were met by hydroelectric generation under the then existing drought conditions, generation from the WPPSS 2 nuclear station, and "other generation" that generally is not subject to economic dispatch.[215] Mr. McCullough then determined the thermal resources in the Pacific Northwest that would have been available to meet the remaining NWPP load. The WSCC 2000 Summer Assessment provides a detailed breakdown of the resources that were available in the U.S. portion of the NWPP to meet those loads. Mr. McCullough adjusted those available resources for planned outages and the actual Hunter outage.[216]

Mr. McCullough performed a dispatch analysis pursuant to which he first dispatched the coal resources in the Pacific Northwest region to meet the remaining load, and then the combined cycle units, and finally the high cost natural gas units.[217] The dispatch analysis indicated that the region's coal resources would have been dispatched to serve load in the Pacific Northwest during the months prior to November 2000 and after March 2001. Low cost natural gas units would have been operated from November 2000 through March 2001, and high cost natural gas units would have been operated in December 2000 and February 2001.[218]

Using information in FERC Form 423, which provides the monthly fuel costs for most of the units in the NWPP, it is possible to calculate operating costs on a resource-by-resource basis.[219] However, in light of the severe time constraints imposed by the Commission on this preliminary evidentiary hearing, Mr. McCullough based his benchmark price on the marginal cost of the highest cost unit in each category, *i.e.*, coal, and low and high cost natural gas units.[220] Accordingly, the results of Mr. McCullough's analysis were conservative for two reasons. First, he used the marginal cost of the highest

[214] Exh. NPG-1 at 13, lines 1-5.

[215] *Id.* at lines 4-5.

[216] *Id.* at 14, lines 3-5.

[217] *Id.* at 14, lines 7-10.

[218] *Id.* at 15, lines 1-3.

[219] *Id*. at 15, lines 6-7.

[220] *Id.* at 15, lines 7-16.

cost unit in each category even though that unit actually may not have been dispatched.[221] Second, absent the price distortions in the California spot markets and taking into account the reduction in the California loads, there were thousands of megawatts of low cost generation in California that would have been available to supply power to the Pacific Northwest during this period.[222] Mr. McCullough added 3.00 mills to cover variable operations and maintenance costs.[223]

Mr. McCullough's analysis of the appropriate benchmark price does not, as it should not, take into account the dysfunction, including the distortions in the prices, in the California PX and ISO spot markets. Rather, as he notes, it is consistent with the operation of the competitive Pacific Northwest spot market over the past 20 years:

> We have two decades of experience with bulk power markets in the Pacific Northwest. These results reflect the vast majority of market behavior we have observed since 1980. They also reflect good economic logic. Plants are block dispatched in merit order. Prices reflect the incentive required to bring up a unit. There are no arbitrary "market mechanisms" where state officials attempt to direct the market or market participants exert market power.[224]

Contrary to claims by various TFG witnesses, a benchmark for the refund period based on a marginal Pacific Northwest unit is fully consistent with the unified, integrated operation of the California and Pacific Northwest sub-markets. As Mr. McCullough explains:

> Distortions in the California market clearly set the prices for the entire WSCC market, including the prices in the Pacific Northwest. However, absent those distortions, the market prices during the period December 25, 2000 through June 20, 2001,

---

[221] *Id.* at 15.

[222] McCullough Rebuttal Testimony, Exh. NPG-68, at 3.

[223] Exh. NPG-1 at 15, lines 16-17.

[224] McCullough, Exh. NPG-1 at 17-18.

> would have been set by the marginal cost of the last unit dispatched in the Pacific Northwest.[225]

In order to calculate market clearing prices for the California PX and ISO spot markets in the San Diego proceeding, the Commission recommended that hourly market clearing prices ("MCPs") be calculated by the California ISO ("CAISO") based on the actual incremental heat rate of the regional marginal generating unit, average daily spot gas prices, a creditworthiness adder and an operation and maintenance (O&M) adder. The methodology utilized by Mr. Movish for calculating market clearing prices in the Pacific Northwest is similar to that used in California by the Commission with several regional changes to produce a clearing price that is more appropriate for the Pacific Northwest.

Mr. Movish utilized a hypothetical marginal unit based upon recent historical data for the Pacific Northwest region.[226] Specifically, data for members of the Northwest Power Pool that filed FERC Form 1 for the year 2000 was utilized. The generating plants with the most inefficient operational heat rates firing natural gas were Avista Corporation's Spokane N.E. plant and Puget's Fredrickson plant. The Spokane N.E. plant reported an average net plant heat rate of 13,004 BTU/kWh, while the Fredrickson plant reported an average net plant heat rate of 12,736 BTU/kWh. Averaging the two heat rates yields a hypothetical marginal unit heat rate of 12,870 BTU/kWh.[227] It is important to note that this application of the heat rate of the least efficient units over all hours during the period presents a worst case scenario for periods when demand was low and a more efficient unit was the marginal unit. This approach overstates the market clearing price that would have been seen in a functionally competitive market.[228] However, considering that no method is perfect for determining the marginal unit for the Pacific Northwest for each hour, the methodology proposed by Mr. Movish provides a reasonable proxy for such a unit,

---

[225]we would expect the surplus resources in California to compete with Pacific Northwest generation and to provide lower cost alternatives during the winter months …. The distortions in the California market were so great and so pervasive that they have tended to obscure the fact that the peak loads in California during the [refund] period … were much lower than in previous years, while the amount of capacity was greater than in previous years.).

[226] Movish, Exh. NPG-33 at 20, lines 5-12.

[227] *Id*. at 20, line 4, line 16 to p. 21, line 4.

[228] *Id.* at 20, lines 8-12.

generally follows the approach taken in resolving overcharges in California, and constitutes an expedient method of resolving refund claims in this proceeding.

Clearly, there are marked differences in gas prices delivered to individual hubs and western sub-regions. Similarly, as the Commission identified in its July 25, 2001 Order, depending on the location of the marginal unit, whether in the North of Path 15 ("NP15") zone, or the South of Path 15 ("SP15") zone, different gas prices will be used in calculating the market clearing price.[229] Accordingly, to appropriately determine market clearing prices prevalent in the Pacific Northwest region, a gas price specifically for that region must be considered. For the Pacific Northwest region, Mr. Movish used the simple average of daily spot prices reported for the Northwest Pipeline hub at Sumas and Northwest Stanfield compressor station hub.[230] These two hubs constitute major flowgates for gas into the Pacific Northwest, and therefore constitute a reasonable source of supply and pricing for gas-fired Pacific Northwest peaking generation.

To calculate the fuel component ($/MWh) of the market clearing price for the Pacific Northwest, Mr. Movish applied the hypothetical marginal unit heat rate of 12,870 BTU/kWh in conjunction with the simple daily average of gas spot prices at the Northwest Pipeline at Sumas and Northwest Stanfield compressor station. To arrive at a calculated market clearing price for the Pacific Northwest spot market, the fuel component was combined by Mr. Movish with the $6/MWh O&M adder as identified by the Commission. McCullough Rebuttal Testimony, NPG-68 at 2. *See also id.* at 3 ('[i]n an undistorted world, no credit worthiness adder was included in the calculation.[231]

The methodology employed by Mr. Movish in calculating a market clearing price does not attempt to incorporate the influences of an unreasonably priced, dysfunctional, California market in its determination of an appropriate market clearing price. Rather, the objective of Mr. Movish's methodology is to determine what prices would have been just and reasonable in the Pacific Northwest spot markets during the period in question based upon a Pacific Northwest located marginal unit which historically has exhibited peaking operational characteristics.

In summary, the methodology employed by Mr. Movish for determining the MCP utilizes the same basic methodology proposed by the Commission in the California

---

[229] *Id.* at 21, lines 10-19.

[230] *Id.* at 22, lines 1-5.

[231] *Id.* at 23, lines 9-17.

proceeding, appropriately uses regional heat rate data and regional historic gas prices, and provides both an un-biased and expedient method that can be applied to quickly correct the harm caused by unjust and unreasonable charges for power in the Pacific Northwest during the period in question.

CALIFORNIA PARTIES:

According to the California Parties, the Commission determined in the July 25 Order that the appropriate methodology for determining refunds in Western Systems Coordinating Council ("WSCC") markets is to develop a just and reasonable mitigated market clearing price on an hourly basis for the relevant time period, and require refunds to be made of prices charged in excess of that mitigated price.[232] The California Parties have utilized the methodology articulated in the July 25 Order, and the unadjusted ISO mitigated market clearing prices which result from it, to develop the value of the refund claim asserted in the testimony in this proceeding.

The California Parties presented their case consistent with the position taken by Commission Staff in developing the template for data submissions in this proceeding, and adopted by Your Honor, in the "Order On Format For Data Submissions," issued August 9, 2001: the refund methodology here should follow the refund methodology ultimately adopted by the Commission in the *San Diego* proceeding. For the same reasons that price mitigation going forward must be equivalent for all regions in the WSCC,[233] the refund methodology must also be consistent across the WSCC.

Because both the refund methodology adopted in the July 25 Order and its implementation remain subject to litigation in the *San Diego* docket,[234] the value of the

---

[232] 96 FERC at 61,516-519.

[233] In the June 19 Order, the Commission held that "[b]ecause these markets are integrated, the mitigation proposal must establish the same prices for all markets." 95 FERC at 62,556. See also Wolak CAL-5 at 12:10-13 ("it may be appropriate, due to the nexus between the California and the Pacific Northwest wholesale markets that substantially the same methodology be used in this proceeding that is ultimately used in the California proceeding in EL00-95").

[234] On rehearing, the California Parties have sought modifications to the following aspects of the July 25 refund methodology: (1) utilization of spot gas prices (rather than the monthly gas prices used in the June 19 order for forward-looking price mitigation); (2)

(continued...)

California Parties' refund claims in this case could change depending on the methodology ultimately adopted.[235] Therefore, the refund claim asserted herein should thus be viewed as the *minimum* value of the California Parties' claim.

Certain variations in the implementation of the July 25 refund methodology should be adapted to the PNW. For instance, it may be appropriate to recalculate the MMCP using PNW gas prices. Measuring CERS actual purchases against such a recalculation would provide yet another measure of the refund claim. However, in the limited time available to submit this filing, the California Parties were unable to obtain the necessary data to make such a calculation.

A just and reasonable rate in the PNW should not include a credit premium such as the 10% creditworthiness adder imposed in the *San Diego* docket. Mr. Movish testified that a credit premium would be inappropriate in developing a just and reasonable rate in the PNW for several reasons: (1) there are no unpaid purchase or sales transactions in the PNW; (2) municipal entities do not constitute any real risk of non-payment; and (3) claimants in this proceeding have paid all of their bills, and paid them in a timely fashion. (NPG-33 at 22:7-20). Mr. Movish concludes that a creditworthiness adder should be imposed only where a market participant has either a demonstrated history of non-payment risk, or has not established experience in meeting transaction payment

(...continued)
imposition of a 10% "creditworthiness adder" on ISO transactions; (3) tripling of the Commission's prior allowance for O&M costs; (4) inappropriately basing mitigated Ancillary Services prices on energy prices; and (5) failing to eradicate the impacts of withholding by declining to impose the must-offer provision on the refund period.

[235] The California Parties have taken the position in the *San Diego* docket that the appropriate methodology for determining just and reasonable rates during the relevant period is to require sellers to make cost of service filings for their entire western portfolios, and to order refunds based on the difference between the unjust and unreasonable prices charged during the relevant period and sellers' actual portfolio cost-of-service. In the alternative, the Commission should determine a just and reasonable rate, and order refunds of charges which exceed that rate, based on the mitigated price methodology applied to the *San Diego* proceeding, with modifications as discussed in the California Parties' Rehearing Request. This position is consistent with the testimony of Dr. Wolak in this proceeding.
(CAL-5 at 14:14-15:15).

requirements. (Id. at 22:20-22). Mr. McCullough testified that the creditworthiness adder was appropriately addressed only to utilities which faced bankruptcy. (NPG-1 at 18:10-19:11). This testimony was unrebutted by any TFG witness.[236]

The creditworthiness adder is inapplicable to CERS' purchases for the same reasons. CERS, a state agency, does not face bankruptcy. Moreover, CERS had access to funding in increments of $500 million, and always kept $400-$500 million on hand, thus ensuring that there was no risk to suppliers of non-payment. (Tr. 854:4-16). CERS has paid all of its bills for PNW purchases in a timely fashion -- sometimes on the same day as a power delivery to avoid being "cut off" by Powerex. (Tr. 868:8-15; Tr. 978:13-17). As CERS has no demonstrated history of nonpayment risk nor insufficient experience making timely payments, it would be inappropriate to impose a credit premium on top of a calculated just and reasonable rate in the PNW.[237]

Where, as here, unrestrained "market-based" pricing caused a catastrophic breakdown, the Commission is required by § 206 of the FPA to set a just and reasonable rate. Consistent methodologies should be used in the *San Diego* docket and in this proceeding to develop just and reasonable rates for the relevant period. The methodology used must fall within a zone of reasonableness related to cost-of-service pricing.[238] The

---

[236] Although the TFG witnesses espouse certain structural differences between the California and PNW markets, they do not propose an alternative methodology for calculating just and reasonable rates in the PNW.

[237] Staff has taken a consistent position. The August 9 "Order On Format For Data Submissions" required that parties submitting the data template in this proceeding report in Column 9 the "CAISO Market Clearing Price . . . filed in Docket No. EL00-95-000 on August 9, 2001." The ISO's August 9 submission reported both an "unadjusted" mitigated market clearing price, and an "adjusted" mitigated market clearing price. The difference between the two was that the "adjusted" price included the 10% creditworthiness adder. In an e-mail message to the parties sent on August 15, staff counsel stated: "We were asked today to clarify whether Col. 9 [on the data template] - - 'CAISO's Market Clearing Price' referred to an adjusted or unadjusted market clearing price. For the Pacific Northwest, you should use the unadjusted price." Consequently, the California Parties' claims articulated in the testimony herein reflect no credit premium.

[238] See *Farmers Union Central Exchange Inc. v. FERC*, 734 F.2d 1486, 1502 (D.C. Cir.
(continued...)

record in this docket is sufficient to immediately award the California Parties refunds in the amount of $1,512,213,967, as discussed further below.[239] Any such award now, however, must provide that the refund amount would increase should the Commission modify the methodology announced in the July 25 Order as the California Parties have requested on rehearing.

TRG:

TFG avers that the prices reflecting competitive market forces and based on active negotiations between buyers and sellers are just and reasonable. *See* Section IV.B.6 below.

STAFF:

Staff asserts that in its June 19 and July 25, 2001 orders, the Commission specified a methodology for calculating refunds for California. If a similar methodology is used here, Staff submits that certain modifications should be considered.

One component of the methodology is the use of the daily spot market price for natural gas. In California the gas price used to calculate the market clearing price is tied to whether the marginal unit is located in the North of Path 15 zone or the South of Path

---

(...continued)
1984) (while the "delineation of the 'zone of reasonableness' in a particular case may, of course, involve a complex inquiry into a myriad of factors . . . the most useful and reliable starting point for rate regulation is an inquiry into costs").

[239] This figure includes the California Parties' claim for refunds associated with exchanges in which CERS participated during the refund period, as described in Issue 2(a). (See *supra* at 16-17). As explained by California Parties' Witness Green, the most generous charge or premium that could be justified for a like-time period exchange would be 20%. (CAL-1 at 8:5-12). To the extent that counter-parties exacted a premium greater than 20% in exchanges in which CERS was a party during the refund period (and some counter-parties exacted as much as a 250% premium), Mr. Green calculated a refund on the basis of the difference between the 20% premium and the higher premium actually charged, multiplied by the unadjusted mitigated market clearing price. The results of this refund methodology are reflected on CAL-12. The California Parties claim a refund of 361,165 MW/h associated with exchanges, or $46,612,324.

15 zone. Thus, the California methodology recognizes the location of the marginal unit and the probable source of the gas used to run it.

Use of these gas prices as applied to determine a market-clearing price in California may not be appropriate for transactions in the PNW. The natural gas used to generate power in that region also comes from Canada. Use of Canadian gas prices or spot prices at different trading points may more adequately reflect costs.

Mr. Movish for the Net Purchasers Group testified that to determine appropriately the market clearing prices prevalent in the PNW region, a gas price specifically for that region must be considered. Ex. NPG -33 at 20-21. He agreed that as in California, it would be appropriate to use the simple average of the spot price as reported by *Gas Daily*, NGI's *Daily Gas Price Index*, and Inside FERC's *Gas Market Report*. He recommended using the prices at the Northwest Pipeline at Sumas and Northwest Stanfield compressor station. *Id.* at 21. [240]

The methodology for California also calls for a ten percent creditworthiness adder. The Commission found such an adder was appropriate and necessary. The Commission noted that in the California proceedings payment of overdue amounts had not been assured. However, in the instant proceeding, there are no allegations that sellers in the PNW have not been paid by PNW buyers. [241]

Issue 2e: Did sellers of electric energy in spot market bilateral sales transactions in the Pacific Northwest for the period December 25, 2000 through June 20, 2001 charge unjust and unreasonable prices?

CALIFORNIA PARTIES:

According to the California Parties, the Commission, in a series of orders to date concerning the wholesale power market dislocations and wholesale power pricing abnormalities both in California and the Western regions of the United States, has determined that unjust and unreasonable rates were charged by sellers in the California market. The Commission has also recognized, in extending price mitigation to the entire WSCC area, that there is a critical interdependence among prices in the ISO's organized

[240] *See also* Ex. NPG- 4 at 26.

[241] Mr. Movish also testified that to the best of his knowledge, there are no unpaid purchase or sales transactions in the PNW. Ex. NPG-33 at 22. *See also* Ex. NPG-4 at 26; Ex. NPG-1 at 19-20.

spot market, the prices in the bilateral spot market in California and the rest of the West, and the prices in forward markets. This interdependence is most evident in the interactions between the California market and the PNW market.

California Parties maintain that due to the dysfunctional nature of the California market, which demonstrated the importance of the inelasticity of demand in both markets, the California market poisoned the PNW market, creating in the PNW market the same type of unjust and unreasonable prices that were being experienced in the California market. Prices in the PNW during the refund period clearly were unjust and unreasonable. The record is replete with empirical evidence demonstrating the lack of any predictable difference in prices between the two regions. CAL-7, taken from the February 1, 2001 report of the Department of Market Analysis of the California ISO, depicts average prices during December 2000 and January 2001 in and outside of California. It provides evidence that sellers of electricity will arbitrage any significant price difference between the PNW and California. As California Parties' Witness Dr. Pechman noted, spot prices in the PNW during the refund period hit an average price for peak hours of $610/MWh and for many months averaged $300/MWh. (CAL-14 at 5:16-17; *see* also, Stegeman, NPG-16 at 16:366-372). Witness Hart, also testifying on behalf of the California Parties, noted that prices charged CERS by Powerex for spot market sales adjusted periodically and unilaterally by Powerex, averaged $462 MW/h. (CAL-9 at 5:6-7). Similarly, Witness Movish for Tacoma and the Port of Seattle testified that, due to dysfunctions in the California market, much higher prices were experienced than actual market conditions would dictate. PNW electric utilities purchasing energy in California were paying higher prices for California sub-market source power. This resulted in a spillover effect into the PNW market. PNW power suppliers, therefore, were able to price at the California ISO and PX price, which was higher than in a functionally competitive market. This, in turn, led to a continuing escalation of both futures and spot market prices throughout the PNW, as well as for bilaterally agreed prices for forward contracts. (NPG-33 at 13:20-25, 14:1-5).

Dr. Pechman testified that "the failure of the spot market in California contaminated the PNW power market by providing the opportunity for generators in the PNW to sell into the California market at very high prices which reflected market power present in California." (CAL-14 at 10:3-6). Similarly, Mr. McCullough testified that "any increase in hourly sales [in the PNW] has simply reflected the unsettled conditions at the California ISO." (NPG-1 at 8:9-10). Mr. McCullough further testified that "[d]istortions in the California market clearly set the prices for the entire WSCC market, including the prices in the Pacific Northwest." (NPG-68 at 2).

Thus, the California Parties argue that a major consideration of the Commission in electing to extend price mitigation to the entire WSCC area was its conclusion in the June 19 Order that "[t]here is a critical interdependence among the prices in the ISO's organized spot markets, the prices in the bilateral spot market in California and the rest of the West, and the prices in forward markets." (CAL-14 at 3:19 - 4:7). This interdependence was graphically demonstrated between the California and PNW markets in CAL-14 at 4, which shows the tight relationship of California ISO average real time energy costs and WSCC spot prices in the PNW and Southwest.

To pretend that the dysfunctional market in California did not also create unjust and unreasonable rates in the PNW, as suggested to the Commission by the TFG, simply defies reality. Even Enron Witness Van Vactor corroborated Dr. Wolak's testimony, and testified that the California/PNW exchanges have created a single continuous market in which scarcity is experienced simultaneously by all parties, bidding up prices for all. (ENR-1 at 7:24 - 8:1-3). TFG Witness Dr. Jones conceded that runaway prices in California influenced prices in the PNW. (PPL-1 at 11:6 - 12:2, and footnotes 6 and 7 ("it would have been irrational for sellers to ignore the opportunity cost of selling to California when evaluating sales to the Northwest.")).

Further, Seattle's Dr. Mason testified on rebuttal that structural differences between PNW and California markets do *not* imply that the markets are economically distinct. Rather, Dr. Mason testified that whether markets are "close" depends on "the effect price changes in one market have on the other." (NPG-62 at 6:25 - 7:6). Dr. Mason observed that there was "abundant evidence that price changes in California lead to changes in PNW." (*Id.*)[242]

As Seattle City Light witness McCullough cogently noted, the scarcity value discussed by numerous TFG witnesses simply reflects the distortion that should be corrected by establishing just and reasonable prices. Starting in May 2000, the market apparatus in California created an artificial market for energy in the WSCC. Since May

---

242

Similarly, FERC Staff took the position, adopted by Your Honor, that all seller data submissions in this case must include an hourly comparison of the prices charged to the unadjusted mitigated California ISO market clearing price developed in the *San Diego* proceeding. Staff based its position on the Commission's June 19 Order, applying "the same mitigated price for all markets in the WSCC. See "Order on Format for Data Submissions," issued August 9, 2001 at 6, 9 (adopting Staff's position and requiring submission of the ISO mitigated price with the template submissions).

2000, the price paid in California, and the opportunity cost for all transactions in the WSCC, were the distorted prices in the California market. (NPG-68 at 6-7).

In summary, California Parties argue, prices paid in the PNW market during the period in question were unjust and unreasonable. The prices were not the product of a workably competitive market, since they have no relation to cost of service based prices or the highest cost operating unit. The prices reflect the operation of the dysfunctional California market. The Commission has determined that unjust and unreasonable prices were charged in the California market due in part to the fact that no viable explanation for such prices has been demonstrated. The same applies here. The Commission should find that unjust and unreasonable rates have been charged in the PNW and should order refunds to remedy this situation.

Several witnesses for the TFG have argued that all prices charged in the PNW bilateral market were just and reasonable. The gravamen of these arguments is essentially that the market during the time frame in question was "workably competitive," and that the premiums over cost of service or marginal cost were justified as scarcity rents or opportunity costs. Their postulations are not supported by the facts.

Initially, according to the California Parties, the TFG testimony ignores the Commission's orders on the California market, and the unjust and unreasonable prices created by the dysfunctional market in California. Nor is there any mention of the Commission's determinations relative to the critical interdependence between prices in the California market and prices in the PNW. The predicate for the testimony of the TFG witnesses is that the PNW bilateral market is only properly viewed on a stand-alone basis. On its face, this predicate fails.[243]

Witness Jones, for example, opined that the tremendous increase in prices experienced during the refund period merely represented opportunity costs or scarcity rents in an environment of drought, increase in natural gas costs, generating unit outages and tight supplies. (PPL-1 at 5:1-12). Witness Jones further claimed that this type of sustained price spike is economically necessary and desirable if generation investment is to be properly encouraged. (PPL-1 at 13:5-12). These claims are meritless. As the

---

243 Essentially, the TFG position is a collateral attack on the Commission's determinations to date concerning the California market. To hold that the prices charged in the bilateral PNW market are just and reasonable necessarily implies that the California market prices were also just and reasonable.

Commission recognized and the evidence shows, the market was not workably competitive.

Efficiency in competitive prices is attained when there is a competitive equilibrium price, where the value of the unit to the marginal buyer (marginal benefit) is equal to the cost of producing that unit (marginal cost). (NPG-62 at 2:24-27, 3:1-4). During the time period in question, the PNW market was not routine. As Witness McCullough testified, the market prices would have been set by the marginal cost of the last unit dispatched had the market been workably competitive, absent the distortions in the California market. (NPG-68 at 2). Indeed, before May 2000, the dispatch of plants in the PNW reflected a very clear relationship between the marginal cost of the highest cost operating unit and market prices. (NPG-68 at 4).

The Commission determined that marginal cost pricing best approximates competitive prices.[244] In its application of its market price mitigation to both the California and Western markets, the Commission concluded that the effective competitive market clearing price is the proxy marginal cost price of the last unit dispatched because this approach is consistent with bidding that would occur in a competitive market clearing

244 The Commission noted that, in a competitive market with demand response, high prices during times of reserve deficiency would be legitimate scarcity rents. However, given the lack of demand responsiveness in the California market, when the market realizes that reliability targets are missed, suppliers have a greater incentive to supply at prices above what they would ordinarily bid in a competitive market. Because of the lack of demand response, these prices may not reflect what the market would have established as appropriate scarcity rents and, therefore, may not be just and reasonable. 95 FERC ¶ 61,115 at 61,361. The same holds true for the PNW market, certainly for the California Parties. As Witness Pechman testified, it was well known that demand was inelastic in the California market. As Dr. Pechman noted:

> The demand curve was we do anything to keep the lights on. There was great social disruption as a consequence of the early rolling blackouts and the DWR was charged with buying power in order to keep the lights on in the state and so, therefore, there was no elasticity. There was no room to adjust to different prices to say no, I can't buy at that price. There were no mechanisms in place in which to reduce demand.

Tr. at 1038. California Parties Witness Hart testified similarly, *supra*.

auction in which each supplier has the incentive to bid competitively at its marginal costs.[245]

The sellers argued that all variable costs and fixed costs should be in the calculation of marginal costs, including opportunity costs, scarcity values and marginal capacity value.[246] The Commission found that this was unnecessary because a competitive market will not simply reimburse firms at their own marginal cost, since those firms with marginal costs below the market clearing price will receive scarcity rents to cover their fixed costs.[247] Using running costs as a proxy for marginal costs still permitted more efficient generators scarcity rents because they will receive the price of the least efficient unit dispatched. Id. In its June 19 Order, the Commission confirmed that using the marginal cost of the least efficient unit dispatched best replicates prices in a competitive market,[248] and that opportunity costs are not appropriate because energy that is available in real-time cannot be sold elsewhere.[249]

Contrary to the sellers' assertions, the allowance of unjust and unreasonable price levels is not necessary to promote investment in generation. The ordering of refunds will not eliminate adequate price signals required to stimulate adequate investment. As Dr. Pechman stated, generators will invest in power plants if they can expect a reasonable return on their investment. Experience shows that generators are willing to develop generation facilities at prices considerably lower than those experienced in the PNW during the applicable time period. (CAL-14 at 4:17 - 5:3). Indeed, generators or investors will base power plant decisions on expectations of future prices, and not the experience in 2000 through June 2001. The Commission has accepted the current

---

245 95 FERC ¶ 61,115 at 61,354.

246 *Id.* at 61,363.

247 *Id.* at 61,363.

248 95 FERC ¶ 61,418 at 62,560.

249 *Id.* at 62,564.

mitigated price of $92 MW/h as not adversely affecting incentives for new generation. (CAL-14 at 5:9, 13-15, 6:7-8).

Likewise, Dr. Jones' definition of a competitive market is flawed. Dr. Jones has modified the standard criteria of competition to allow the ability to institute an increase in price, as long as the increase is not significant or sustained. (CAL-14 at 8:10-19). However, in concluding that the electricity trade in the PNW is workably competitive, he failed to evaluate whether the price increases were sustained or significant. In fact, the testimony of Powerex witnesses refutes Dr. Jones by suggesting that the forward price was appropriate for determining Powerex's opportunity costs (PWX-5 at 4-5) and by describing high and sustained forward prices. (PWX-6 at 10:5, 6-13, 15; 14:3). Thus, if Powerex believed that the market was truly competitive, it would not have used the forward price curves that Dr. Tabors recommends. In addition, the forward market prices are not just and reasonable because the prices cannot be justified on the basis of production costs or replacement costs. (CAL-14 at 13:15-17).

In essence, the collective wisdom of the TFG "dream team" of experts on this issue (see, e.g., Tr. 999:12-14) is that the markets functioned as expected and prices increased to reflect changed circumstances. This claim erroneously assumes, of course, that the PNW market was competitive, and uninfluenced by the California price distortions. As Dr. Pechman explained, these assumptions have no basis, so the conclusion is simply wrong:

> If the Pacific Northwest power market were competitive as he [Dr. Jones] suggests, much of what he claims would be true. However, because market power was present almost all of the time in the California market during the relevant period, prevailing prices in the spot market were far above efficient competitive levels. In turn, because generators in the Pacific Northwest could sell into this market, their offered contracts were at prices far above competitive levels. Since buyers in the Pacific Northwest had nowhere else to turn they were forced to purchase electricity at excessive prices and provide windfall profits to generators. Thus, the price signal was not, as Dr. Jones suggests appropriate and likely to lead to socially optional decisions but rather a distinction that would lead to inefficient decisions and wealth transfer. (CAL-14 at 18:11-19).

The California Parties conclude, in the end, TFG's entire case rests upon the unrealistic and undemonstrated assumption that the PNW market operated in a workably competitive vacuum and was not in any way connected to the California market. TFG's arguments that the prices charged were just and reasonable are unfounded and represent little more than a collateral attack on the Commission's Orders.

TFG:

TFG argues that the prices charged reflected scarcity conditions in a competitive market in which demand had increased but supply had not. They are, by definition, just and reasonable.

STAFF:

Staff states that the number of sellers has not been precisely identified, and the mitigated market clearing price in California is as yet undetermined, it is not possible to give a definitive answer to this question. Further, sellers have not had an opportunity to justify their spot prices. Additional proceedings would be required.

2. f. Did Any Seller Exercise Market Power, Or Violate Any Conditions Or Limitations Of Its Market Based Tariffs Or Agreements Entered Into Under The Western Systems Power Pool Agreement?

NPG:

NPG argues that this "issue," which was not among those identified by the Commission, was included at the insistence of the members of the TFG, who evidently hold the erroneous belief that absent some other unlawful activity, their charges for electricity cannot be found unjust and unreasonable, no matter how high above marginal cost they might be. As the Federal Power Act and the previous law of this case demonstrates, this issue is irrelevant. Nowhere in the Federal Power Act are sellers of electricity in interstate commerce given the right to charge or collect unjust and unreasonable prices so long as they have not exercised market power or violated any conditions or limitation of any applicable tariff or contract. Moreover, the Commission has already imposed prospective price mitigation and also refund requirements in the San Diego Docket upon finding only that the California market structure presented the opportunity for potential exercises of market power that resulted in prices that were outside the zone of reasonableness.[250]

That is not to say, however, that proof of market power does not exist. It can be found, for example, in TFG Exh. 20,[251] and in the very fact that sellers were able to command exorbitant prices for a sustained and significant period of time. With additional time and access to information, such as that already provided to the Commission *in camera*, the members of the NPG have no doubt that a strong case can be made that market power existed and was exercised during the relevant period.

CALIFORNIA PARTIES:

California Parties argue that suppliers in the PNW exercised market power. Equally important, suppliers in the PNW, regardless of their own market power, extracted windfall profits because of the market power that tainted the California markets during the relevant period. Under either scenario, the existence of market power forced purchasers of power from the PNW to endure unjust and unreasonable rates.

The record establishes that electricity suppliers exercised market power in the PNW markets during the relevant period. Dr. Wolak testified that the exercise of market power is made possible by the limited supply response of other actual and potential competitors to price fluctuations such that one or more firms can unilaterally increase the price of electricity paid by load serving entities. (CAL-5 at 5:21-6:2.) Witness Hart described this exact situation. CERS purchased from Powerex only when other lower-priced sources of supply were completely exhausted. At that point, CERS was

---

[250] In the November 1 Order, 93 FERC at 61,350, the Commission stated: "While this record does not support findings of specific exercises of market power, and while we are not able to reach definitive conclusions about the actions of individual sellers, there is clear evidence that the California market structure and rules provide the opportunity for sellers to exercise market power when supply is tight, and can result in unjust and unreasonable rates under the FPA." And in the Order of December 15, 93 FERC at 61, 999, ("we disagree that, absent exercise of market power, prices are necessarily just and reasonable. Our analysis must be . . . based on a determination of whether the rate falls within a zone of reasonableness.").

[251] Tr. 982.

confronted with a “take it or leave it” proposition at exorbitant prices unilaterally set by Powerex. (CAL-9 at 4:10-17 and 6:2-7; Tr. 893:6-16.)[252]

TFG-20[253] demonstrates Powerex’s capability to set prices independent of the market. TFG-20 verifies that Powerex not only charged prices based upon unjust and unreasonable forward price curves for determining the price of power it offered to sell to CERS, but also exercised additional market power by charging CERS even higher prices. Importantly, on numerous occasions reflected in TFG-20, Powerex charged California greater than the purported $500 “risk adjusted forward value of summer energy.” (Peterson PWX-6 at 10.) The ability to consistently charge prices over a period of time in excess of the purported forward price curve is, in itself, a further strong indicia of market power. It is also consistent with TFG’s own definition of market power -- “the ability profitably to maintain prices above competitive levels for a significant period of time.” (Adamson ENR-10 at 13:7-9.)

The TFG also improperly seeks to engraft a culpability standard on the FPA. Wrongful behavior is not the standard. There is no requirement in the law for the Commission to determine that any particular seller exercised or intended to exercise market power before the Commission may take remedial measures under § 206. Rather, the prerequisite both to fixing just and reasonable rates to be “thereafter in force,” under § 206(a) and to order refunds of charges in excess of such just and reasonable rates under §

---

[252] Moreover, as noted by Dr. Pechman for the California Parties (CAL-14 at 11:20-23 - 12:1-3), Mr. Ken Peterson, the CEO of Powerex Corp., described Powerex’s market power in his testimony. That testimony provides, in pertinent part: “Powerex was able to supply large quantities of power to CDWR in peak and superpeak periods, often times on no more than 10 to 20 minutes advance notice, and with tremendous hourly swings in the level of purchases scheduled by CDWR. This shaping of power deliveries for CDWR could only be achieved by drawing on the hydroelectricity generation facilities of BC Hydro. Many of these deliveries literally enabled California to keep the lights on. . . .” (PWX-6 at 8.) As stated by Mr. Peterson, the choice CDWR had was to buy from Powerex or go black. In other words, Powerex had market power to charge greater than competitive prices.

[253]As noted above in footnote 24, TFG-20 purports to be a graphic depiction of the price for wholesale transactions between Powerex and CERS as set forth in the work papers of Mr. Green introduced, into the record by Powerex as TFG-19.

206(b) is simply that the rates charged have been unjust and unreasonable.[254] As set forth previously herein, the Commission has repeatedly found that the California wholesale electricity market was insufficiently competitive to ensure that unfettered market based rate authority would produce just and reasonable rates and that California and the rest of the West are interdependent.[255]

The tight correspondence in price fluctuations between the California ISO day-ahead and real time prices and spot prices in the PNW, detailed by numerous witnesses in this proceeding, reinforces the accuracy of the Commission's prior findings. (See, e.g., Pechman, CAL-14 at 3:19-4:9; Movish, NPG-33 at 12-17; McCullough Rebuttal, NPG-68 at 2, 6, 13 and 17; Saleba, GSS-1 at 3:15-4:2, 4:15-6:6 and 7:4-11).

Given the Commission's acknowledgment of the inextricable interdependence of the California and PNW markets, the TFG's argument is, in essence, that they may permissibly "piggy back" on prices set by participants that do have market power and exercised that market power. This argument patently violates § 206. Suppliers in the PNW were charging and benefiting from a market power determined price.

TFG:

TFG asserts no seller exercised market power or violated any condition or limitation in its tariff or WSPP contracts. *See* Section IV.B.7 below.

BONNEVILLE/BPA:

Bonneville argues that no party has alleged in this proceeding that BPA exercised market power or violated any rate schedule or agreement, and BPA stated in its testimony that no such rate schedule or agreement violations occurred. BPA-1 at 21. This is the case, in part, because BPA does not establish market-based tariffs under the Federal Power Act. BPA's power rates are established under the Northwest Power Act, not the

---

254 See e.g. *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956) ("The condition precedent to the Commission's exercise of its power under § 206(a) is a finding that the existing rate is 'unjust, unreasonable, unduly discriminatory or preferential'").

255 November 1 Order, 93 FERC at 61,349; December 15 Order, 93 FERC ¶ 61, 294 (2000) at 61,984; June 19 Order, 95 FERC at 62,545; *Id.* at 62,547.

Federal Power Act, and the Commission's authority to review BPA's power rates is specifically prescribed in the Northwest Power Act. BPA's surplus firm power is sold under a Northwest Power Act rate schedule governing BPA's firm power products and services. *Id.* This rate schedule has a ten-year term and was reviewed and approved on a final basis by the Commission in 1996. *Id*. BPA's WSPP power sales were all made by mutual agreement. *Id.*

STAFF:

The Staff did not submit any testimony on the issue of market power. However, it states that Ex. TFG-20 is a graph which plots one seller's price to one buyer over most of the relevant time period. [256] It tends to show that this seller sold consistently at a set price, which happens to be well in excess of the $150.00 California market clearing price adopted by the Commission in its December 15, 2000 order. The graph, however, shows significantly more variations after late April 2001. Should further proceedings be ordered, similar examinations of sellers' prices may be warranted.

RECOMMENDATIONS

The record establishes, that the PN market is part of the broader Western power market. The purchase and sale of electricity is carried out pursuant to the rules and guidance of the WSPP Agreement. For decades the PNW has enjoyed a robust and liquid wholesale power market, which is characterized by hundreds of traders and multiple trading points. Exhibits ENR-1 at 3; AE-1at 3; NPG-1 at 7: 14-17.

Over 60% of the PNW's power supply comes from hydroelectric. The prevalence of hydroelectric generation provides an inexpensive source of power, but it also subjects load serving entities to weather conditions (*i.e.,* drought and resulting low-flow conditions). Faced with seasonal and year-to-year variations in water and storage availability, PNW parties have long been accustomed to buying and selling with each other and with parties outside the region to ensure that supply matches demand.

Following construction of the Northwest-Southwest Intertie in 1970, seasonal exchanges of power with California, Arizona and New Mexico became commonplace. The normal water flow from May to July, coupled with a winter peaking demand profile, has enabled the PNW to export large volumes of "economy" energy during summer

---

[256] See discussions at Tr. 908-914 (in camera session) and Tr. 987-995. The later discussion of this document in the transcript was not held in camera.

months, when its loads are low, but loads to the south are at their highest levels. In return, the PNW historically has relied on surplus thermal generation from California and the Desert Southwest to supplement local supplies during winter cold spells, when loads to the north are high in comparison to loads to the south. Exh. ENR-1 at 9.

The presence of an extensive and comparatively uncongested transmission network (on a historical basis) also has contributed to the development of a fluid wholesale power market in the PNW. BPA owns and operates the majority of the high voltage transmission facilities in the region. Long before the advent of Commission Order No. 888,[257] BPA allowed parties access to its transmission grid. Exh. AE-1 at 3. As a consequence, the Mid-Columbia hub in Eastern Washington is recognized as one of the most flexible trading points in the nation. Exh. ENR-1 at 12.

Due to a robust bilateral wholesale market, there has never been a centralized power exchange in the PNW. There is no single market clearing price in the region. Exh. ENR-10 at 12. Energy is bought and sold continuously on a bilateral basis, subject to the principles set forth in the WSPP agreement. Each utility is free to choose how to meet its firm load requirements as it sees fit and no one is captive to a single market or a single point of supply. As noted by Eugene Water and Electricity Board ("EWEB") witness Spettel, transactions "are negotiated at arms-length between willing buyers and sellers … [and] often times reflect unique and specific circumstances between the parties engaged in each transaction." Exh. NPG-68 at 7. See also TR. at 566-67; Exh. ENR-1 at 13; Exh. PWX-1 at 21; Exh. BPA-1 at 22; Exh. ENR-10 at 11; Exh. IE-2 at 13; Exh. PPL-1 at 21.

As a result of the availability of many traders and trading points, purchasers in the PNW have numerous options in developing a portfolio of power supply. Depending upon their perceived needs and tolerance for risk, load-serving entities can buy power for the next hour, the next day, the balance of the month, monthly, quarterly or for a term of one or more years. Exh. NPG-74 at 6. As observed by Dr. Tabors, risk-averse load-serving entities can assemble a portfolio of long, medium and short-term contracts and, thereby, minimize their exposure to volatile spot market prices. Exh. PWX-1 at 21. In the PNW, shortages in the availability of hydroelectric generation are constantly assessed and general trends are predicted months in advance, consequently PNW purchasers tend to make extensive use of forward contracts (*i.e.*, transactions with durations longer than 24

---

[257] *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) ("Order No. 888").

hours). Indeed, over 99% of the City of Seattle's net purchases during the December 25,2000-June 20, 2001 period were made under forward contracts; the corresponding figure for Tacoma Power approximates 62.5%. Exh. PWX-3.

Two additional characteristics of the PNW market are directly relevant to the justness and reasonableness of bilateral spot market prices in the region. First, demand in the region is more price sensitive (that is to say, "elastic") than in other parts of the West due, in part, to the presence of a number of energy intensive industries, such as aluminum smelting. Exh. ENR-1 at 11. Those consumers have exercised and, indeed, regularly exercise their ability to respond to price signals by decreasing consumption. Demand responsiveness by PNW consumers was a very important factor in bringing prices down in the PNW in 2001, and an important indicator that the PNW markets were functional throughout the potential refund period. Second, prices, particularly in the forward markets, are extremely sensitive to movements in the cost of natural gas. Exh. ENR-10 at 24-27. Electric prices rose dramatically in the PNW when increased demand for natural gas caused prices to skyrocket in the latter part of 2000, as drought conditions restricted the availability of hydroelectric generation.

There are factual differences between the California ISO/PX markets and the PNW. In California, load-serving entities (comprised almost entirely of California's three large investor-owned utilities) were forced to divest much of their generation, to sell power from what generation remained to the ISO/PX and then buy back all of their requirements through a centralized clearing house at an administratively determined price. Because that price was tied to the bid of the most-expensive generating unit operating within the market at the time, it did not necessarily reflect the value placed on those transactions by any individual buyer. Exh. PWX-1 at 16. Additionally, having to rely entirely on spot market sales, California buyers were effectively prevented from hedging their risks or balancing their portfolio through forward contracts. In its November 1, 2000 Order,[258] the Commission expressly found this to be a fundamental problem with the California market. Exh. ENR-10 at 11.

Buyers in the PNW faced no such constraints. Load-serving entities, for the most part, retained their own generation, were free to negotiate supply contracts on their own terms and conditions in spot and forward markets, and, as a consequence, paid prices that reflected the value that willing buyers and sellers placed on those transactions in the face of supply constraints. Exh. PWX-1 at 16. For many years PNW buyers have been free to enter into short, medium, and long-term contracts to achieve a hedged and balanced

---

[258] November 1 Order, 93 FERC at 61,359.

portfolio. “Participants in PNW markets made their own decisions regarding purchasing strategies and contract terms, not only in the period covered by this proceeding but for years leading up to this period.” Exh. PWX-1 at 6:14-16; 7:8-10.

The hearing record documents in detail the successive shocks that the western power market experienced leading up to and during the period at issue:

> The disruption and price explosion in the WSCC from May 2000 through June 2001 were the consequence of market fundamentals, exacerbated by financial uncertainty and confusion. There were four compounding events that caused price to rise and to remain at elevated levels for fourteen months. In the first wave, the summer of 2000, high demand growth and hot weather combined to create capacity shortages in California, with resulting price spikes. In the second wave, cold weather smacked the PNW earlier than expected and with much greater severity than normal. The cold weather coincided with the season in which the natural stream-flow in the region’s hydro system is at its lowest, and with the planned reconditioning of many of California’s thermal generators due to heavy usage in the summer of 2000. The natural gas delivery system was stretched to its limit, inventories reached historic lows, and gas prices peaked at thirty times the level of the year before. In November and December, precipitation remained at record low levels and the power industry became increasingly anxious about the possibility of a serious drought. The Power Planning Council’s October warning appeared all the more prescient. In January 2001, the first formal projections on snow pack became available and provided alarming evidence of dry conditions, bringing a third wave of dread to the Western power market. In the meantime, PG&E and Southern California Edison were not able to pass on to their customers the high prices they had had to pay for power in November and December due to frozen rates imposed during market restructuring. Both utilities defaulted on their obligations to their suppliers, including many PNW utilities. The growing financial risk created the fourth and final wave, as essential trade shrunk and the WSCC split apart in autarky.

Exh. ENR-1 at 19:13-20:11.

The evidence further shows that The PNW was faced with an extreme and rare contraction in available supply. To accommodate the shortage, prices rose dramatically, but that is exactly what they are supposed to do. Higher prices provoked a drop in demand and an increase in alternative supplies. Once it was clear that the functions of demand and supply would accommodate the projected shortfall, prices collapsed with extraordinary speed. Exh. ENR-1 at 19:13-21:1; *see also* Exh. NPG-16 at 16:327-17:349; Exh. IE-2 at 2:22-3:4; Exh. IE-4, Appendix F.

The market for electricity in the PNW was affected to varying degrees by these factors, all of which worked together to raise the price of electricity as is normally expected in a workably competitive market when supply is scarce. Ex IE-2 at 25-26.

Furthermore, the evidence also establishes that the PNW utilities were generally forewarned of potential supply shortages. For instance, since 1999 BPA had expressed concerns about a potential energy deficit in the region. Exhs. Enr-1 at 13:22-15.2; NPG-74 at 9:21-10:5; NPG-4 at 14:305-310; NPG-16 at 16:362-366.

As Ms. Green and others acknowledged, in 2000 and 2001, the PNW experienced the worst drought in the last 50 years. See Tr. at 592:19-593:4; *see also* Tr. at 610:20-611:10. Combined with increased demand from population and technology growth ("one dot-com company can use 20-40 megawatts per day, the same as the entire [Seattle-Tacoma] airport."), this drought caused an unprecedented increase in prices. Tr. at 610:20-611:10. The record also establishes that increased demand for electricity contributed to increased input costs (*i.e.*, higher demand for electricity resulted in higher demand for natural gas, causing the price for gas to increase). *See* Exh. ENR-10 at 28:4-5, 12-15 ("In addition to dramatic changes in market conditions for natural gas in the Northwest, a second major factor that must be considered is the impact of hydrological conditions…. Just as the natural gas market was making it more costly to offer forward electricity contracts, the weather was reducing the ability of hydroelectric operators to enter into such forward commitments. Available supply was therefore contracting, which put further upward pressure on prices.").

In addition, in California, increased demand, unavailable generation, and credit concerns with California buyers all exacerbated the situation. Exh. NPG-53 at 5:4-10.

The record evidence demonstrates that the PNW market for spot sales of electrical energy was at all times between December 25, 2000 to June 20, 2001 competitive and functional. Exh. PWX-1 at 20:16-21:3.

Dr. Jones explained that there has been no showing of market power or other evidence indicating members of the TFG did any thing other than reflect their competitive market expectations in their bilateral contracts. Exh. PPL-1 at i.

The evidence shows that the Pacific Northwest performed just as workably competitive markets would under adversity. For instance,

- "As prices increased during 2000-2001, investors/suppliers responded, proposing new capacity additions. On the demand side of the price signal, consumers went to work, reducing energy use and adopting conservation techniques…. As a consequence of this competitive response, prices for electricity in the PNW have fallen dramatically." Exh. PPL-1 at 14:7-13.

- "Notwithstanding the shortages of energy in the Pacific Northwest, the market was sufficiently competitive to enable purchasers to be selective about the energy product that they were purchasing. As a consequence, purchasers were able to dictate certain key terms of transactions to sellers, such as firmness and point of delivery." Exh. PSCO-1 at 11:12-16.

- Port of Seattle reported in May 2001, "[m]any experts are forecasting not only sustained periods of high prices but also shortages of electricity in 2001. Staff believes it is critical that we not only take measures to reduce the cost of electricity through conservation…, but find a reliable and stable source of electricity for the Airport's future needs." Exh. TFG-8 at 1, PS 1570.

- Port of Seattle also reported "[f]our different companies have approached us on … the option of self-generation…. Implementing energy conservation projects and programs [has] reduced [our] consumption by over 10% already and may get to 15% in another month. Long term we believe we can reduce energy consumption by 20-25% from our current base." Exh. TFG-5 at PS 1529.

Mr. Van Vactor also explains how the Western power market crises moderated:

> The Western power crisis has alleviated due to a significant drop in consumption. In the PNW, many industrial customers agreed to shut their plants down and sell the power back to the supplier. In California, the long-

> postponed retail rate increase finally went into effect in June [2001]. That combined with a conservation program dropped demand by more than five percent. At the same time new, and more efficient, generating resources came on-line. Summer weather returned more or less to normal and spot prices have returned to normal levels. Ex. ENR-1 at 20:14-21:6.

Dr. Tabors observed., “[T]he bilateral markets in the PNW, . . . which have been in existence for more than two decades, worked through a confluence of adverse circumstances in 2000 and 2001, and have now regained equilibrium. Conservation resulted from price signals, demand was reduced, load was shed, and prices came down. These are not indications of a broken market in the PNW, but of one that works. It should be left alone to function..” Exh. PWX-12 at 10:6-11.

The evidence also establishes that claimants witnesses conceded that sellers who engaged in the business of marketing electrical power face no barriers to entry. *See* Tr. at 770:24-772:3. Dr. Mason testified unconditionally that for sellers who are marketers that “[t]here are no barriers to prevent them [from] buy[ing] and resell[ing].” *Id.* Likewise, another of the claimants’ witnesses, Dr. Pechman, admitted that he conducted no econometric or price elasticity studies to support his contention, contrary to the evidence, that demand in the PNW does not respond to price.

Seattle witness Mr. McCullough observed:

> One reason why real world commodity exchanges avoid the administered prices of the California model is that these types of markets have proven relatively easy to manipulate. Manipulation of prices in the WSCC outside of California is difficult since no central authority can be “gamed.”

Exh. NPG-1 at 7:19-22.

It is interesting to note that refund advocates do not seek any structural changes in the operation of the markets governed by the WSPP Agreement.

In making my recommendation I am cognizant that the Commission has rightly refused to extend refund liability to other California markets in which prices were apparently “influenced” by the ISO and PX prices but where no structural flaws existed. Additionally, the Commission has stated in the past that it should minimize its intervention in otherwise well-functioning market mechanisms.

> We emphasize that, by design and definition, spot markets must be allowed to reflect the price swings which capture their temporal nature. In markets such as these, which are the closest to when demand must be met, sufficient supply often manifests itself by dramatic price drops while tight supply can produce dramatic price increases. This is the nature of spot markets. *Those who remain in the spot market for buying their residual load or selling their residual supply should be there in full recognition of the effects on price of last minute sales and purchases*.[259]

The record evidence establishes that Tacoma chose to take the risk of high spot market prices. Exh. NPG-57 at 3. If the position of the refund claimants is accepted, they would be relieved of the consequences of their conscious economic decisions at the expense of a functioning competitive market in which a vast majority of the PNW purchasers during this period accept responsibility for the choices they made. For instance, Seattle recognized in September, 2000 that the Centralia sale left it "more dependent on the market than we have been historically." Exh. PPL-1 at 21 n.19. Tacoma likewise sold its [80 MW] share of the Centralia production. Exh. NPG-57 at 3.

Purchase of forward contracts was another option available throughout the PNW to reduce reliance on the volatile spot market. Tr. at 656:15-657:4. In September 2000, TFG member Powerex offered forward contracts for delivery of power during the first quarter of 2001 at $75.50 and $81 per MW. Tr. at 689:11-690:21; Exh. TCE-2. Tacoma now asks the Commission to give it, through refunds, rates it rejected in the marketplace. The correlation between spot market prices and forward market prices is not one-to-one. In fact, by one measure, only 57 percent of the variance in third quarter 2001 forward prices was explained by variance in the Dow Jones Mid-Columbia Index during the first and second quarters of 2001. Tr. 724:6-25-725:1-13. Utilities separate short-term from forward-market trading and compare the prices quoted for these different products when they make resource decisions. Exh. TFG-1; Tr. 581:7-19; Tr. 598:4-8; Tr. 643:9-23; Tr. 656:15-25-657:4. Long-term transactions (i.e., those involving power delivery that is not either immediate or pre-scheduled over a very limited number of days) are the most

[259] December 15 Order, 93 FERC at 61,996 (emphasis added).

predominant and important class of transactions in the region. Exh. NPG-1 at 8:22. Exh. NPG-1 at 10:2-3.

For a number of years preceding the refund period, wholesale electricity market prices in the PNW were, according to Tacoma's Ms. Stegeman, "quite low." Exh. NPG-16 at 14. *See* also Exh. IE-2 at 28:15-20. By electing to rely on the spot market during this period, refund claimants benefited financially. Now the refund claimants are rebalancing their portfolios by returning to BPA or by acquiring interests in new generation facilitites. Exh. TFG-8 at 2. Tacoma installed a 48 MW diesel generation project and entered into exchange agreements with other power suppliers. Exhs. NPG-15 at 18; NPG-57 at 5. These responses by refund claimants are proof that the market is functioning properly and that it continues to offer choices to its participants.

Buyers who wanted to hedge in the Pacific Northwest could have done so. There were various tools available. Exh. IE-2 at 14.

Therefore, in light of the above I recommend that the Commission not order refunds in this case because the prices were not unreasonable and unlike the California ISO/PX, the market is a competitive market. Furthermore, the prices in the California ISO/PX were not the only factor driving the prices. There was a drought, which limited supply, the price of natural gas rose and demand increased. Spot market bilateral sales constituted only a small percentage of the total volume of transactions in the region because forward contracts are heavily relied on. Spot market sales took place under diverse prices, terms and conditions. Most market participants were both buyers and sellers. In reaching my recommendations I am cognizant of prior Commission orders establishing market based pricing to foster competitive markets. In the case before me, where all transactions are bilateral transactions under the aegis of the WSPP Agreement this is more compelling. The prices were agreed to between willing buyers and willing sellers.

In making my recommendation and based on NPG's and California Parties' allegations I have re-read the April 26 and June 19 orders and conclude that these orders do not support these parties contentions that the Commission has already determined that the prices in the PNW were unjust and unreasonable. First, if that were the case, why would the Commission institute this preliminary evidentiary hearing. Second, the June 19 order refers to the dysfunctionalities of the California market. Third, and most significant, (a factor not mentioned by these parties) the Commission ordered the western market mitigation plan "based upon the need for uniform pricing throughout the western region." slip op at pg. 47. Finally, the April 26 order started an investigation, it was not a decision on the reasonableness of the rates.

There is no evidence of the exercise of market power in this case. For instance, Seattle witness Mr. McCullough stated in his rebuttal testimony that: "The Pacific Northwest market over this time period was a price taker," which means that no entity in the region was able to exercise market power. Other expert witnesses admitted that they had no evidence of market power in the PNW. Philip Movish, witness for Tacoma, Port of Seattle, and Northern Wasco, admitted that there were a substantial number of sellers in the region, particularly in this time period. Tr. at 727. An allegation of the exercise of market power was made on cross examination of Dr. Tabors. As Dr. Tabors explained, exhibit TFG-20 shows the price line for the fixed price sales by Powerex to CDWR. The exhibit also shows the prices Powerex charged for other sales to CDWR during the refund period, and purchases made for aggregation services. (Tr. at 914-15, 920-22). California bought 45,000 MWH at $500 per MWH price, under a $22.5 million 3 day credit limit set by Powerex. This was equilavent to a $225 million monthly credit limit. TR at 868:22 - 869:7; 870:21-25. Powerex made more than 30,000 sales, purchases and exchange transactions in the market during the relevant period. It was a net spot market purchaser in the PNW during the potential refund period (Exh. PWX-10, p.3). Tr. at 862:5-863: 26; Exhs. PWX-1 - 6 at 15; PWX 5 at 6. I find that the evidence in this case does not show the exercise of market power by any one company.

At Issue 1, above, I made recommendations concerning the claims of the CDWR/CERS. If the Commission orders additional proceedings, the issues set forth above, may need to be considered (whether these transactions were spot market or not, etc.).

Although I ordered that non-jurisdictional utilities submit data in this proceeding in order to develop the record, I agree with Bonneville and other non-jurisdictional entities that the rationale previously used by the Commission to assert jurisdiction over non-jurisdictional entities does not seen to apply to this market because of the differences between the Pacific Northwest and the California ISO/PX.. If the Commission orders refunds, this issue must be addressed. If refunds are ordered and the non-jurisdictional entities are excluded, this would differentiate sellers subject to refunds in the market. In making this recommendation, I give significant weight to the fact that the majority of the transactions in this market are bilateral transactions under the WSPP Agreement.

Staff's explanation of the data submissions corroborates the Commission's statement that unraveling these transactions is to be mildly stated a complex task. The data submission have been certified to the Commission as part of the record in this proceeding. The data submissions are incomplete. It appears that all entities who may have sold into the PN market during the relevant time period did not submit data, of 226 members of the WSPP, only 56 entities responded to the order by either providing data or indicating they had no eligible transactions. To determine entities who did not, a reconciliation with FERC Form No. 1 would have to be undertaken. In addition, as stated above there are problems with the data submitted. If the Commission decides to order refunds, portfolios of resources would have to be undone to determine upstream vendors. Furthermore, from the submissions it cannot be determined whether the power was used to serve the buyer's loads in the PN or was resold again, perhaps into California, nor the power that originated or was transmitted through the PNW. The data does show that most of the transactions were made pursuant to the WSPP Agreement or market based rate tariffs on file with the Commission, or bilateral contracts. The data shows a range of prices listed above.

Based on my recommendations above I am not making any recommendations on the specific methodology to be used for determining the amount of refunds. However, I set forth above, all the parties' proposals. I find persuasive that because of the distinctions of the market, if the Commission orders refunds, adjustments must be made from the refund protocols established in the California proceeding. Staff's recommendations are persuasive with regard to this matter.

The record shows that although the California prices affected the prices in the Pacific Northwest, this was not the only thing driving up the prices in the PNW. Therefore, under these circumstances, and based on the specifics of the PNW market and the evidence developed in this case (the market has for years been a competitive market, there is ample competition in the market based on the number of sellers, buyers and trading points, the market shows instances of self correction) I recommend that the Commission not order refunds in this case. I am not persuaded by the arguments made by the California Parties and the NPG. They failed to establish by preponderance of the evidence that the prices in the Pacific Northwest were unjust or unreasonable. Furthermore, I find compelling that the transactions in this market, unlike the California market, are bilateral agreements, and have been so for years, under the WSPP Agreement. It bears mentioning that the majority of participants in this proceeding were against refunds.

3. Are refunds lawful or appropriate for spot market bilateral sales transactions in the Pacific Northwest for the period December 25, 2000 through June 20, 2001 and what is the extent of any potential refunds?

The Washington Utilities and Transportation Commission, Oregon Office of Energy, and Oregon Public Utility Commission maintain that it is not equitable to order refunds because of limitations on the Commission's jurisdiction over many buyers and sellers of wholesale power in the Pacific Northwest, and because of the Commission's direction to examine only spot market transactions. Under these circumstances refunds would be discriminatory, and disruptive of orderly regulation. It asserts that there is no objective measure for determining whether the prices were unjust and unreasonable and to what magnitude. A large portion of the power bought and sold in the Pacific Northwest is sold by non-public entities. If the Commission cannot legally impose refund obligations on these sales, the burden of paying refunds will fall on a limited class of jurisdictional sellers in the region; and the benefit of receiving refunds will be available only to buyers who bought form those same sellers.

NPG:

NPG contends that sellers charged, and consumers paid, unjust and unreasonable prices in the Pacific Northwest spot markets during the refund period, whether refunds are "lawful and appropriate" is a matter for the Commission, rather than the Presiding Judge, to determine. The Commission has not asked the Presiding Judge to advise it on this matter.[260] Nevertheless, such refunds are certainly "lawful" because they are authorized by Section 206(b) of the FPA.[261]

Ordering refunds of the unjust and unreasonable charges borne by the consumers of Seattle, Tacoma, Port of Seattle, Eugene, Northern Wasco and other Pacific Northwest communities is certainly "appropriate" NPG argues. The Commission has ordered refunds for the benefit of California's citizens,[262] and consumers in the Pacific Northwest should also be protected by the Commission from unjust and unreasonable charges. Even Puget, a prominent TFG member, has acknowledged the unfairness that would otherwise result: "it is unfair and unduly discriminatory to protect wholesale purchasers in California . . . and yet deny similar protection in another part of essentially the same market, *i.e.*, the Pacific Northwest."[263]

---

[260] *See* July 25 Order, 96 FERC at 61,120.

[261] *See* 16 U.S.C. § 824e(b) (1994) ("the Commission may order the public utility to make refunds of any amounts paid, for the period subsequent to the refund effective date . . . in excess of those which would have been paid under the just and reasonable rate").

[262] *See* July 25, Order, 96 FERC ¶ 61,120.

[263] Puget Complaint at 10. Contrary to the impression it has since sought to convey, *see, e.g.*, Tr. 69. Puget's Complaint explicitly recognized that relief that was "prospective" on October 26, 2000 could ultimately involve refunds. The Complaint specifically

(continued...)

Congress did not distinguish between or among the forms of contract under which remedies for unjust and unreasonable prices may be imposed. Instead, it directed the Commission's attention to the subject matter of the transaction – the price charged for energy. When unjust and unreasonable prices have been charged, irrespective of contract type, Congress provided the Commission with remedies. The Commission's delegated authority to grant relief from unjust and unreasonable rates arises from Section 206 of the Federal Power Act, which then creates the statutory obligation to fix a new rate or to fix practices to be thereafter observed, if the Commission finds that a rate no longer meets the just and reasonable standard.[264] Thus a bilateral contract under which unjust and unreasonable prices were extracted is susceptible to remedy by the Commission, and refunds are an appropriate and legal remedy under the Federal Power Act, according to NPG.

Furthermore, NPG asserts, the parties opposed to refunds – the TFG – contend that unjust and unreasonable prices should be left unrectified because determining refunds allegedly would be too complex a matter. Having invented the inapt term "ripple claims," the TFG through its witnesses claim that "[i]f refunds are ordered, other market participants (perhaps most) will be forced to assert 'ripple' claims, unwinding a vast web of transactions across the entire western market."[265] These allegations about "ripple claims" are a red herring. Parties opposed to refunds requested and received permission during a prehearing conference *not* to introduce in this preliminary proceeding information on any "net" amounts or refunds due them from other entities. They made

(...continued)
requested that: [I]f and to the extent any refund is called for in response to PSE's petition, PSE respectfully requests that the refund effective date be set, in accordance with Section 206 of the Federal Power Act (16 U.S.C. § 824e(b), sixty (60) days after the date of the filing of this Complaint. Puget Complaint, at 11. *See also* Puget Complaint at 13. Notably, Puget's Complaint declined to seek an earlier effective date not on the ground that the Commission could not lawfully do so, but because Puget thought an earlier refund date would be "unfair" due to "the operation of the seasonable flow of power between California and the Pacific Northwest." Puget Complaint at 11, n. 7.

[264] 16 U.S.C. § 824e(a).

[265] Van Vactor, ENR-1 at 3.

this request so as to avoid being in the awkward litigation posture of opposing refunds while at the same time identifying refunds they claimed were owed them.[266]

According to NPG, all parties are quite capable of revealing *at one time* the bilateral spot market purchases and sales they made, the prices they charged and paid, and to whom and by whom they are owed refunds. The NPG members that have submitted affirmative refund requests did so, in a mere fifteen days.[267] Once the Commission clarifies the bilateral spot market transactions to be subject to refunds, and adopts a market mitigation price, all Pacific Northwest market participants will be able to submit purchase and sales data and their refund claims, if any. Rather than the TFG's metaphorical "ripples" or the "unwinding" of a spider web, refunds can be determined in one simultaneous reconciliation.

Additionally, NPG avers that TFG witnesses make various claims to the effect that granting refunds would constitute "regulatory intervention" in a "well functioning bilateral electricity market" and "would skew incentives and undermine . . . efficiency."[268] They overlook the fact that the Commission has already determined that Pacific Northwest bilateral spot markets were dysfunctional and has established prospective price mitigation for such markets through September 30, 2002.[269] Moreover, TFG witnesses fail to explain how net sellers making, and net purchasers receiving, a one-time refund payment would change the prospective prices and economic incentives facing market participants. It obviously would not.

---

[266] *See, e.g.*, Transcript at 104 (Counsel for Constellation: "I don't want to have to stand out there and demand refunds that I don't think are appropriate . . . . But I also don't want to inadvertently waive my rights in the event something goes forward"); Transcript at 140, lines 10-12 (Counsel for Duke Energy: "by making the ripple testimony such a central feature here, in effect you're asking everybody to take that side of the case"); *id.* at 141, lines 6-12 ("But to ask parties simultaneously to be arguing against affirmative claimants . . . and at the same time have to take the exact opposite position just strikes us as putting us between a rock and a hard place."); *see also* the responses of the TFG members to the Second Discovery Requests of the City of Tacoma and Port of Seattle.

[267] *See, e.g.*, Exhs. NPG-70 through - 72 (the Direct Cases and Requests for Refunds filed by NPG members).

[268] Van Vactor, Exh. ENR-1 at 3-4.

[269] *See* June 19 Order, 95 FERC at 62,549.

Finally, NPG asserts, TFG witnesses make the disingenuous claim that the unjust and unreasonable Pacific Northwest prices should not be rectified because parties seeking refunds allegedly have "unclean hands." With no support but their own misconstruing of NPG testimony, TFG witnesses contend that NPG members were able to "cash in" by "purchasing power . . . when prices were low and selling . . . when prices were high."[270] In particular, the TFG contends that the period covered by this proceeding fails to include summer months when, the TFG alleges, NPG members were net sellers.[271] These claims are disingenuous because NPG members *would like* to extend the refund period back to cover the summer of 2000 and have not profited from sales of surplus energy.[272] Indeed, the City of Tacoma and Port of Seattle have already filed a Petition for Review of the July 25 Order on precisely this issue.[273]

In sum, NPG concludes, it is certainly legal and entirely appropriate for the Commission to order refunds of the unjust and unreasonable charges collected in the Pacific Northwest.[274]

---

[270] Jones, PPL-1 at 24.

[271] Tabors, PWX-1 at 45.

[272] *See, e.g.*, Rebuttal Testimony of Paula S. Green, Exh. NPG-67 at 7. ("Seattle supported the longer refund period requested in the California settlement conference"); *id*. ("Seattle was a net purchaser in the spot market for the entire period May 2000 to June 20, 2001"); *id*. ("Seattle has not profited, and does not profit from surplus sales").

[273] *See City of Tacoma, Washington, and Port of Seattle, Washington v. FERC*, Case No. 01-1337 (D.C. Cir., filed July 31, 2001), consolidated with *Turlock Irrigation District v. FERC*, Case No. 01-1289 (D.C. Cir., filed June 27, 2001).

[274] Whether the Commission may exercise jurisdiction over non-public utilities is presently under review by two United States Courts of Appeals. *California Public Utility Commission v. FERC*, Case No. 01-71051 (9th Cir., filed June 29, 2001); *Turlock Irrigation District v. FERC* (D.C. Cir., filed June 27, 2001), consolidated with *City of Tacoma, Washington, and Port of Seattle, Washington, v. FERC*, Case No. 01-1337 (D.C.Cir., filed July 31, 2001). Until such time as the Commission's Order of July 25, 2001, is modified or reversed in that regard, it is the law of this case that the Commission has jurisdiction over such utilities for purposes of this proceeding. July 25 Order, *slip op.* at 25-30. *See, e.g., Christiansen v Colt Indus. Operating Corp.*, 486 U.S. 800, 816 (1988), *citing Arizona v. California*, 460 U.S. 605, 618 (1983). *See also* 18 Moore's

(continued...)

CALIFORNIA PARTIES:

California Parties argue that the Commission has the authority to order refunds in this case and should do so in order to prevent a windfall to PNW sellers and to deter future market abuses. California consumers are entitled to a refund in excess of $1.5 billion. The Commission may lawfully order refunds pursuant to its authority under § 206 of the FPA,[275] for spot market bilateral transactions in the PNW during the refund effective period. The Commission has broad authority to implement remedial measures in response to unjust and unreasonable rates, including the express authority to order refunds:

> At the conclusion of any proceeding under [§ 206], the Commission may order the public utility to make refunds of any amounts paid . . . in excess of those which would have been paid under the just and reasonable rate . . . which the Commission orders to be thereafter in force.

According to the California Parties, the establishment of the December 25, 2000 refund effective date is lawful. As the Commission discussed in the July 25 Order, § 206 authorizes the Commission to establish a refund effective date no earlier than 60 days after the date that a complaint is filed or the Commission initiates an investigation.[276] Here, the refund effective date is 60 days after the date on which the Puget complaint was filed. Refunds are a form of equitable relief, and the general rule is that the Commission should order restitution when it would "give offense to equity and good conscience" if a refund were not ordered.[277] The key considerations include whether a party will

(...continued)
Federal Practice, § 134.20[2] (Matthew Bender 3d ed.).

275 16 U.S.C. § 824e.

276 96 FERC at 61,505.

277 *Towns of Concord, Norwood and Wellesley v. Fed. Energy Reg. Comm'n*, 955 F.2d 67, 75-76 (D.C. Circ. 1992) citing *Atlantic Coast Line R.R. v. Florida*, 295 U.S. 301, 309 (1935)

experience a windfall or unjust enrichment absent a refund, whether a refund will deter future abuses, and whether the equities favor a refund.[278]

During the refund period, California Parties maintain, there was an enormous transfer of wealth from buyers to sellers. The clearest single example of this transfer is the price paid for purchases made by CERS in the PNW on behalf of California ratepayers in order to "keep the lights on." CERS purchased power at an average rate of $390 MW/h; it paid Powerex, which supplied approximately one-third of CERS' PNW volumes, an average rate of $462 MW/h. This compares to a current mitigated price under the Commission's prospective market mitigation plan of $92 MW/h. (Pechman, CAL-14 at 5:14-17). By virtually any standard, the prices charged for power by most sellers resulted in windfalls.[279] The Commission has taken steps to mitigate the price and therefore provide some relief on a going-forward basis. Equity requires that refunds now be ordered retrospectively in order to correct the market dysfunctions that clearly occurred and permitted sellers to take advantage of buyers.

Additionally California Parties claim that ordering refunds will advance the Commission's goal of fostering markets that self-regulate in the future. As California Parties Witness Dr. Pechman explained, the ordering of refunds will establish a much-needed precedent for appropriate pricing behavior:

> At this point, the de-regulated power markets have no frame of reference as to what is "just and reasonable" pricing behavior. Refunds will establish precedent and begin to

---

278 *Koch Gateway Pipeline Co. v. Fed. Energy Reg. Comm'n*, 136 F.3d 810 (D.C. Circ. 1998) (windfall); *Laclede Gas Co. v. Fed. Energy Reg. Comm'n*, 997 F.2d 936 (D.C. Circ. 1993) (reasonable accommodation of the relevant factors); *Wisconsin Electric Power Co. v. Fed. Energy Reg. Comm'n*, 602 F.2d 452 (D.C. Cir. 1979) (broad equitable latitude in fashioning refund orders).

279 As Seattle Witness McCullough observed in rebuttal, the prices charged for electricity far outstripped increases in the component production costs, such as the cost of natural gas:

> Any party to the price excursions of the past eighteen months knows that the spark gap between electricity and gas climbed to unheard of levels after May 2000. Simply stated, an electric price shift of 1,000% cannot be explained by a gas price shift of 100%.
> (NPG-68 at 11).

> establish norms of behavior. These norms of behavior will form the basis of self-policing on the part of marketers and generators.

(CAL-14 at 20:16-21).

California Parties further contend that the sellers argue that an order of refunds will retard investment in generation and slow down the process of recovery in the Western markets.[280] As California Parties' Witness Dr. Pechman explained in rebuttal, however, refunds will have no such effect. The mitigated prices that the Commission has already ordered on a prospective basis are more than sufficient to induce investment. As investment is based upon expectations of future prices, generators already know that the high prices they enjoyed during the period through June 2001 are irrelevant to future expectations. (CAL-14 at 4-6).

Powerex Witness Peterson suggested in his testimony that CERS gained a competitive advantage in the PNW by locating employees in the control room of the California ISO, the California Parties argue. (PWX-6 at 7). Counsel for Powerex pursued this issue vigorously on cross-examination of California Parties' Witnesses Hart and Green. As the record presently stands, however, this is now a non-issue. As explained by Mr. Hart and Mr. Green on cross-examination, during the time CERS employees were stationed at the ISO, they had no access to information in the ISO control room. (Tr. 831:3-9). They were segregated from ISO employees, seated facing away from everyone else in the control room, given blank screens on their computer consoles, and afforded no special access to information. Moreover, procedures were in place to prevent ISO employees from sharing information with CERS employees. (Tr. 976:4-20).

Quite apart from the fact that the record in this case demonstrates that information is not shared between ISO and CERS employees, California Parties maintain, Powerex's insinuations ignore two fundamental realities. First, this record contains no evidence that ISO employees had information that could have been useful to CERS employees in negotiating bilateral contracts in the PNW.[281] Second, as a practical matter, CERS

---

[280] TFG Witness Jones, for example, argued that "Ordering refunds is adverse regulatory intervention in a process that was producing the very signals that would prevent future price spikes." (PPL-1 at 4:1-4).

[281] Given the volume of purchases CERS made from Powerex and the unrebutted testimony that

(continued...)

employees needed to be on-site at the ISO in order to determine, on an hour-by-hour basis, what transactions CERS needed to back the real time grid needs or "net short."[282] As Mr. Hart explained on cross-examination, CERS could not effectively arrange transactions on an hour-by-hour basis based on hour-by-hour ISO requirements other than through physical presence. CERS was "not set up electronically" to obtain the necessary information from the ISO for hourly transactions. (Tr. 975:3-16). Accordingly, none of the concerns articulated in the Commission's July 25 Order concerning CERS interactions with the ISO in the California market[283] have any application here.[284]

In addition, the California Parties contend that Powerex Witness Peterson suggests in his testimony that, because CERS was delegated "sole authority" to determine that its

---

(...continued)
CERS only purchased from Powerex as a last resort, it should be obvious that CERS did not have the benefit of "inside information" from the ISO that helped it to obtain more favorable prices.

282 The role of CERS is to purchase power in order to "fill the gap" between power supplied by California's investor-owned utilities ("IOUs") and municipal utilities and the requirements of California electric consumers. Forecasts of the shortfall between supplies and demand are performed on a day-ahead, hour-ahead and "real time" basis, and the net shortfall (hence "net short") is purchased and supplied by CERS. On a "real time" basis, the ISO, as the clearinghouse, is the only entity in a position to know the quantity of the "net short" that CERS must meet.

283 96 FERC ¶ 61,120 at 61,515.

284 Counsel for Powerex also made much of the fact that Mr. Hart had not specifically instructed CERS employees concerning the Commission's Standards of Conduct for Transmission Providers. (Tr. 821:14-24). To begin with, these standards do not apply to CERS, which is not a transmission provider. (Tr. 974:19-20). In any event, as Mr. Hart testified, CERS employees and ISO employees were instructed to refrain from sharing information with each other:

> They were not given nor did they have access to any other information with respect to any information that the ISO would have had with respect to any bids or anything else.
>
> (Tr. 827:19-21).

purchases were "just and reasonable" for flow-through purposes to consumers under California law, CERS already has conceded that all prices that it paid were "just and reasonable" for FPA purposes. (PWX-6 at 5-6). This is nonsense. CERS' determination of "reasonableness" of its own purchases under California law[285] focuses only on whether there were less costly alternatives -- i.e., whether wholesale power was available at a lower price. CERS makes no attempt to second-guess this Commission's judgment whether particular wholesale prices charged by sellers were "just and reasonable," nor could it do so. (Tr. 977:23 - 978:12). AB1x does not supplant this Commission's determination of what constitutes a "just and reasonable" rate.

The market dysfunction that manifested itself in California and the rest of the Western electricity market during 2000 and 2001 is a complex problem with multiple causes. Although it would be difficult (and perhaps futile) to attempt to trace the market dysfunction to a culpable party, the identity of the *beneficiaries* of the PNW market dysfunction could not be more clear. As pointed out by California Parties Witness' Dr. Pechman, refusing refunds to California consumers because of well-intentioned efforts at deregulation by California officials and the Commission simply blames the victims for a problem beyond their control. This problem was obvious to all market participants, and resulted in market power that enabled sellers to charge unjust and unreasonable prices to California consumers, the California Parties maintain. (CAL-14 at 15:1-16).

Additionally, the California Parties argue that Powerex cannot credibly maintain that it reasonably relied to its detriment on Mr. Hart's statement, that CERS would not seek refunds. *First*, as explained in Mr. Hart's rebuttal, Mr. Hart made it clear from the outset that, although CERS would not assert a claim, he could not speak for other California agencies who might seek refunds on behalf of consumers. (CAL-9 at 8:3-9). *Second*, at the time Mr. Peterson asked for the assurance, all participants in the PNW market were well aware that refunds were being discussed openly and considered by such parties as the California AG. (Tr. 973). Powerex does not claim that it ever attempted to secure any assurances from the California AG or other consumer representatives. *Third*, as the whole of Mr. Peterson's and Mr. Hart's testimony makes clear, Powerex's "no refund" assurance demand was fundamentally coercive. Powerex was well-aware that CERS needed Powerex to help it "keep the lights on" in California. Such coercive behavior should not be rewarded by absolving Powerex of its obligation to pay refunds for the benefit of California consumers. *Fourth*, Powerex did not even ask for the "no

285 California Water Code § 80110, added by AB1x-1, TFG-14.

refund" assurance until May 16, 2001, four months after it commenced sales to CERS, and only one month from the conclusion of the refund period, according to the California Parties. (PWX-6 at 19; CAL-9 at 8).

STAFF:

Staff argues that it is undisputed that the Commission has the discretion to order refunds.

In the California proceedings, the Commission determined that all sellers of energy in the California ISO and PX spot markets, both public and non-public utility sellers, should be subject to refund liability for the applicable periods. The non-public utilities have filed numerous applications for rehearing of the Commission's determinations. During the course of the hearing the Presiding Judge denied a motion by the City of Burbank to certify the following question: "Whether, under Section 201(f) of the FPA, the Commission can exercise jurisdiction over non-public utilities' bilateral sales in the Pacific Northwest, which were outside of any "centralized" and "organized" ISO or PX spot market?" The Presiding Judge found (1) that non-public utilities play a greater role in the PNW and their participation is essential to develop a record in this proceeding; (2) that the Commission previously decided to include non-jurisdictional entities in proceedings involving refunds; and (3) that the July 25 Order did not exclude non-jurisdictional facilities from the PNW proceeding.

As shown on Staff's Exhibit S-8, the total refund amount claimed by parties in these proceedings is $1,931,354,858. Other parties to this proceeding have advanced reasons why certain of the claims shown on Ex. S-8 should not be considered in the total amount because they are not refund claims, [286] are claimed by a California entity, or reflect all definitions of the spot market as shown on the template.

The definition of spot market as well as the inclusion or exclusion of the California claims, would affect the magnitude of refunds. For example, six non-California parties, Clark PUD, EWEB, Northern Wasco, City of Seattle, Port of Seattle, and City of Tacoma requested a total of approximately $461.5 million in refunds. This is based on total MWh of 1,892,072. If the spot market is narrowly defined as 24 hours or less, the total MWh

---

286

At the hearing, a representative for SMUD indicated that the claims outlined in its testimony of August 17, 2001 and reflected in Staff's Exhibit S-8, were more in the nature of counter-claims and ripple claims, rather than a direct claim for refunds. Tr. at 783-85, 1248.

for such transactions account for 4.15 percent of total MWh. Under Staff's proposed spot market definition of up to one month, the total MWh involved would be approximately 80 percent of the total. Similarly, in dollar terms, if the spot market is defined as 24 hours or less, then refunds for such transactions would amount to only 14.34 percent of total claimed refunds. If the definition is up to one month, such transactions would account for approximately 75 percent of total claimed refunds.

When California transactions (CDWR) are included in the refund analysis, the results shift to reflect the enormous number of California transactions and the fact that they are primarily 24 hours or less. California transactions of 24 hours or less account for approximately 6,691,706 MWh out of a total California claim of 6,802,944 MWh. Similarly, $1.45 billion of California's $1.46 billion refund claim is tied to transactions of 24 hours or less.

In terms of calculating refunds, Staff included in its template a column for the California ISO market clearing price. This column reflects hourly mitigated market prices as provided by the California ISO to Judge Birchman in the San Diego proceeding on August 9, 2001. These prices could be used as a potential starting point for calculating any refund claims. Staff notes, however, that the prices reflected on the template are subject to change pending Judge Birchman's certification of the California ISO data to the Commission and the Commission's further orders. Ex. S-3 at 9-10.

TFG:

On the other hand, the TFG asserts that refunds related to sales into PNW spot markets from December 25, 2000 through June 20, 2001 are unlawful under the Federal Power Act, are adverse to the public interest, and would be, in any event, impossible to administer. Intervenors cannot pursue their refund claims in this docket based on Puget's Complaint, which never related to refunds and was long ago abandoned by Puget. It is inappropriate for intervenors to substitute themselves for Puget and use this docket to launch retroactive refund claims.[287] Puget is no longer prosecuting its Complaint for any purpose. Tr. at 727. Moreover, Puget's Complaint did not seek refunds and was limited to relief for sales "into" the PNW, not exports "out of" the PNW and "into" California.[288] Nonetheless, refund claimants, intervenors in this case, have attempted to expand the

---

[287] This is particularly true here given that Puget's Complaint has been dismissed, *see* December 15 Order, 93 FERC at 62,020, a decision that the Commission has never vacated or modified.

[288] Complaint at 1 n.1, 2, 10-12.

scope of the Puget Complaint and, as a consequence, the very record of the proceedings in this docket. As the Presiding Judge consistently ruled in this case, intervenors must "take the record as they find it."[289] By seeking relief beyond that sought by Puget, Tacoma, Seattle, the California Parties, and other claimants, have not taken the record as they found it, but have sought to dramatically alter and expand its nature and scope. The request for refunds under these circumstances violates the Commission's longstanding policy prohibiting intervenors from expanding complaints initiated by others. To the extent parties wish to prosecute claims beyond the scope of a complaint, such parties must initiate a new Section 206 proceeding.[290] In *Louisiana Power & Light Company*,[291] the Commission explained that it would not treat pleadings (motions, interventions) filed by third parties in a complaint proceeding initiated by another party as the complaint itself.[292] Allowing intervenors to prosecute a refund claim beyond the scope of the Complaint initiated by Puget and beyond the procedural path of that Complaint, including its withdrawal, will therefore improperly expand the function of intervenor to that of a complainant.[293]

---

289 *See supra* note 11 and orders cited therein.

290 *See American Elec. Power Serv. Corp.*, 93 FERC ¶ 61,329 at 62,122 (2000) (rejecting a request for an Section 206 investigation that was made as part of a motion to intervene instead of in a separate request); *ISO New England, Inc., et al.*, 91 FERC ¶ 61,227 at 61,830 (2000) (determining that complaints must be filed separately); *Deseret Generation & Transmission Co-Operative*, 78 FERC ¶ 61,274 at 62,153 (1997) (request for an Section 206 investigation must be made separately in a complaint proceeding; *Arizona Pub. Svc. Co.*, 78 FERC ¶ 61,083 at 61,305 n.20 (1997) (the Commission's "consistent practice" is to reject Section 206 complaints that are filed in motions to intervene or protests). The Commission, in fact, will reject requests by parties on rehearing to treat their original protests as complaints. *See Entergy Services, Inc.*, 52 FERC ¶ 61,317 at 62,270 (1990).

291 50 FERC ¶ 61,040 at 61,062 (1990) ("*Louisiana Power*").

292 *Id.* ("a complaint cannot be submitted as an integral part of a protest and a motion to intervene in an ongoing proceeding; *it does not allow interested parties sufficient notice of the complaint because it is not formally docketed and noticed*") (emphasis added).

293 *E.g., Union Oil of California dba Unocal v. Cook Inlet Pipe Line Co.*, 73 FERC ¶

(continued...)

According to TFG, the filed rate doctrine holds that the only rate that a regulated public utility may legally charge for its services is the one properly submitted to and made effective by the appropriate regulatory authority.[294] The doctrine protects the customer from illegal charges because it bars the utility from charging anything other than the filed rate. The utility too is protected in that its sales at the approved and published rate cannot be later challenged.[295] The "whole purpose" of the filed rate doctrine is to provide the "necessary predictability" to which industry participants are entitled prior to when, rather than after, their business decisions are made.[296]

The Commission observed in the July 25 Order that the filed rate doctrine applies to market-based rates, TFG argues.[297] Wholesale sales by TFG members into PNW markets are made pursuant to market-based rate schedules that each had filed with the Commission and which the Commission accepted. The market rules, (*i.e.*, the WSPP

(...continued)
63,006 at 65,040 (1995) (an intervenor and Commission Staff were prevented from raising issues in a proceeding and directed to raise such issues in a separate complaint filed with the Commission); *see Yankee Atomic Electric Company*, 60 FERC ¶ 61,316 (1992) (intervener free to file a separate complaint); *Nevada Power Company*, 70 FERC ¶ 61,391 (1995) (requiring that a complaint be filed with the Commission pursuant to Section 206 in a separate docket and where parties would be permitted an opportunity to respond).

294 *Arkansas Louisiana Gas Co. v. Hall*, 453 U.S. 571, 577 (1981); *see also, e.g., Montana-Dakota Utilities Co. v. Northwestern Public Service Co.*, 341 U.S. 246, 251-52 (1951).

295 *Montana-Dakota Utilities Co.*., 341 U.S. at 254 (utility "can claim no rate as a legal right that is other than the filed rate, whether fixed or merely accepted by the Commission" and the Federal Power Act withholds "power to grant reparations"); *accord Maine Public Service Co. v. FPC*, 579 F.2d 659, 664, 667 (1st Cir. 1978) (under a final, filed rate, reparation can reach "neither past profits, nor past losses"); *Arizona Grocery Co. v. Atchison, Topeka & Santa Fe Railway Co.*, 284 U.S. 370, 384 (1932) (required to "render rates definite and certain, and to prevent undue discrimination," without exposure to reparations).

296 *Towns of Concord v. FERC*, 955 F.2d 67, 71 (1992) (*citing Elec. Dist. No. 1 v. FERC*, 774 F.2d 490, 493 (D.C. Cir. 1985)).

297 96 FERC at 61,506.

umbrella contract) constitute the mechanism for ensuring that the clearing prices under market-based rates are the product of lawful market forces.[298] In this case there is no claim that the rates charged by any TFG member ever violated the WSPP Agreement. Thus, TFG rates throughout this period were filed rates; they cannot be revised retroactively.

TFG argues that the only exception to the filed rate doctrine (here, the market rates charged under the WSPP contract) occurs when the Commission institutes an investigation under FPA Section 206 into the reasonableness of those rates and establishes a "refund effective date." Section 206(b) provides that "the refund effective date shall not be earlier than the date 60 days after the filing of [the complaint or notice of the Commission's intent to begin a Section 206 investigation] . . . nor later than five months after the expiration of such 60-day period."[299] The refund effective date provisions of Section 206(b) thus assure wholesale power sellers operating under filed rates that they will have formal advance notice, through the refund effective date, when their sales are subject to refund.[300]

According to TFG, the Commission has never established a refund effective date in this docket. Rather, the earliest indication to PNW wholesalers that their sales could be subject to refund occurred in the April 26 Order in Docket No. EL01-68-000, when the Commission opened a Section 206 investigation into WSCC sales "other than sales through the California ISO markets."[301] The order provided that the Commission would establish a refund effective date 60 days after publication of the notice of initiation of the WSCC investigation in the *Federal Register*. This notice was published on May 3,

---

[298] *New England Power Pool,* 90 FERC ¶ 61,141 at 61,425 (2000) (NEPOOL market rules are the filed rate); *NRG Power Marketing, Inc. v. New York Indep. Sys. Operator, Inc*., 91 FERC ¶ 61,346 at 62,162 (2000) ("the ISO Market Rules are the filed rate").

[299] *See also Southwestern Elec. Coop., Inc. v. Soyland Power Coop., Inc*., 95 FERC ¶ 61,254 at 61,880 (2001); *UtiliCorp United Inc. v. City of Harrisonville,* 95 FERC ¶ 61,054 at 61,130 (2001).

[300] Even when a valid refund effective period can be established, however, the Commission retains discretion to deny Section 206(b) refunds unless in the public interest. November 1 Order, 93 FERC at 61,379-61,380.

[301] 95 FERC at 61,365.

2001.[302] Thus, the earliest possible refund effective date for the WSCC investigation (inclusive of the PNW) is July 2, 2001.

The consequence is that the putative refund period – December 25, 2000 through June 20, 2001 – can never become effective. Puget's Complaint was dismissed by the Commission's December 15 Order, and cannot now be used to establish a refund effective date.[303] Nor could the Commission attempt to establish a refund effective date on rehearing of the December 15 Order since the five-month window specified in Section 206 (which began 60 days after the date of Puget's Complaint) for establishing such a prospective refund period cannot be established retroactively; only a refund effective date established within the five-month window under Section 206(b) can provide advance notice. Here, the five-month period expired on May 25, 2001 (Puget's Complaint was filed October 26, 2000). Even if these defects were not fatal to any claim for refunds (and they are), in no circumstances could refunds be associated with contracts executed prior to December 25, 2000. Exh. BPA-1 at 7-8. For these reasons, TFG contends it is legally impermissible, consistent with Section 206(b), for refunds to be ordered for any period relevant to this proceeding.

Additionally, TFG maintains, that the *Mobile-Sierra* doctrine bars refunds of prices negotiated in the PNW under bilateral contracts freely entered into by the complaining parties where, as here, refunds would be adverse to the "Public Interest." Even if the filed rate doctrine were not an absolute bar to ordering refunds in this proceeding (which it is), refunds are prohibited under the *Mobile-Sierra* doctrine for the vast majority of the spot

---

[302] 66 Fed. Reg. 22223 (May. 3, 2001); *see also* June 19 Order, 95 FERC at 62,568.

[303] While Puget initially filed a request of rehearing of the Commission's rejection of its Complaint, Puget withdrew that rehearing request on June 22, 2001. Rule 216(b) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.216(b), provides that such motions for withdrawal become effective 15 days from filing if no motion in opposition is filed within that period or the Commission does not otherwise issue an order disallowing the withdrawal. The Commission issued no such order and, while motions in opposition were filed by some parties, no such parties were participants to the proceeding as required by Rule 212(a), 18 C.F.R. § 385.212(a). Accordingly, Puget's withdrawal of the rehearing request became effective as a matter of law on July 9, 2001.

sales at issue, which were performed under the WSPP Agreement and its service schedules.[304]

The WSPP contract contemplates that all sales under its auspices are final and binding and not subject to abrogation by the Commission, TFG asserts. The WSPP Agreement describes "the legal principles that will control future power sales between the parties." It is based on bilateral trading, with participants using the WSPP standardized contractual terms and conditions to execute transactions. *See* Exh. NPG-74 at 6; Exh. ENR-1 at 10. As described by Staff, the WSPP Agreement is a standardized power sales contract, under which jurisdictional members sell electricity at market prices once they receive market-based rate authority from the Commission. *See* Exh. S-3 at 8:12-13 ("The WSPP Agreement provides that Parties are free to negotiate the specific terms and conditions of a transaction under the service schedules."). EWEB explains that its current WSPP contracts are "negotiated at arm's length between willing buyers and sellers." *See* Exh. NPG-68 at 6. This is effectuated through Schedule C, Section C-3.6 of the WSPP Agreement, which provides that the rates for electricity provided for power sold under its auspices would be at market rates negotiated by the parties. *See* Exh. S-6 at 88. While Section 6.1 of the WSPP Agreement provides that the parties to the contract may make "joint application" to the Commission under Section 205 of the FPA to change the rates agreed upon in the contract, the Agreement does not provide for review under FPA Section 206 by the Commission pursuant to unilateral action of one party to the contract, which is precisely what Tacoma, Seattle, the California Parties, and the other refund claimants are seeking to do. *See* Exh. S-6 at 12-13.

Under the *Mobile-Sierra* doctrine, the absence of a specific provision allowing unilateral changes in rates signifies an intent not to permit one party to the contract (including the instant complainants) to unilaterally seek a modification of the contract rate provisions under FPA Section 206, as would be the case here through retroactive

---

[304] The record shows that the vast majority of PNW sales relevant to this proceeding, as well as the CDWR purchases, are performed under the WSPP umbrella contract. *See* Exh. S-3 at 7 (majority of transactions were made pursuant to the WSPP Agreement); *see also* Exhs. NPG-12, NPG-13, NPG-14, NPG-15, NPG-15a, NPG-15b. Several parties, in fact, have testified that *all* of their transactions at issue in this proceeding – including all of their sales to Seattle, Tacoma, *et al.*, in the PNW as well as those sold in California markets that are the subject of the claims made by the California Parties – were performed under the WSPP Agreement. *See, e.g.*, Exh. CP-1 at 3; Exh. CPS-1 at 2-3; Exh. PWX-6 at 9 (all transactions with CDWR are through the WSPP Agreement); Exh. IE-1 at 7.

refunds.[305] The *Mobile-Sierra* doctrine preserves the FPA's reliance on voluntarily negotiated contracts; arms-length sales under market-based rates are the quintessential example of such contracts. The D.C. Circuit has "repeatedly emphasized the importance of contractual stability in cases involving the *Mobile-Sierra* doctrine."[306] As settled contractual expectations play a crucial role in the scheme of the Act, before the Commission can modify the pricing provisions of a contract, it must demonstrate that the revision will serve a "public interest" beyond the just and reasonable requirement.[307]

The "public interest" standard, which has been described by some Circuits as "practically insurmountable,"[308] is a much more stringent standard than can be met merely showing that the contract prices are "unjust and unreasonable" under of Section 206. In *Sierra*, illustrating what a utility must show in order to be relieved of an "improvident bargain" (a fixed-rate contract that was no longer profitable), the Supreme Court stated:

> the sole concern of the Commission would seem to be whether the rate is so low as to adversely affect the public interest – as where it might impair the financial ability of the public utility to continue its service, cast upon other consumers an excessive burden, or be unduly discriminatory. That the purpose of the power given the Commission by § 206(a) is the protection of the public interest, as distinguished from the private interests of the utilities, is evidenced

---

305 *See San Diego Gas & Elec. Co. v. Pub. Svc. Co. of New Mexico*, 91 FERC ¶ 61,233 at 61,852 (2000); *see also Texaco Inc.*, 148 F.3d 1091, 1095-96 (D.C. Cir. 1998) (citations omitted); *Boston Edison Co. v. FERC*, 233 F.3d 60, 65 (1st Cir. 2000) (citations omitted).

306 *See Potomac Elec.*, 210 F.3d at 409 (citations omitted).

307 *See, e.g., Boston Edison*, 233 F. 3d at 64-65; *Papago Tribal Utility Auth.*, 723 F. 2d at 953. The burden is on the Commission and any party that seeks unilateral contract modification to make this showing. *Transmission Access Policy Study Group v. FERC*, 225 F.3d 667,709 (D.C. Cir. 2000) (emphasis added), *cert. granted sub nom., People of the State of New York and Public Serv. Comm. of the State of New York v. FERC*, 69 U.S.L.W. 3574 (U.S. Feb 26, 2001) (No. 00-568). The *Mobile-Sierra* Doctrine does not apply when parties to a contract expressly provide that the Commission may override the contract's provisions under Section 206's just and reasonable standard. *United Gas Pipe Line Co. v. Memphis Light, Gas & Water Div.*, 358 U.S. 103 (1958). The market-based rate tariffs in the Pacific Northwest do not contain a *Memphis* reservation.

308 *Papago Tribal Utility Auth.*, 723 F.2d at 954.

> by the recital in § 201 of the Act that the scheme of regulation imposed is "necessary in the public interest." When § 206(a) is read in the light of this purpose, it is clear that a contract may not be said to be either "unjust" or "unreasonable" simply because it is unprofitable to the public utility.[309]

According to TFG, none of the complainants testified that transactions arising under the WSPP Agreement have threatened their solvency, have cast upon consumers an excessive burden, or were unduly discriminatory.[310] To the contrary, the witness for the City of Tacoma conceded during the hearing that the WSPP Agreement provides substantial benefits to all potential purchasers in the PNW, and should be preserved intact and unchanged. *See* Tr. at 660, 661. Although the three factors listed in *Sierra* are not exclusive, and other factors can be used to demonstrate that the public interest is hurt, no showing in this regard has been made here.[311] In fact, the public interest factors shown on the record compel the opposite conclusion.

Additionally, TFG maintains, that the Commission already has approved the manner in which the PNW market functions, when it approved the WSPP Agreement. The content of that agreement is the product of a decisional process to which its 220 signatories, including claimants have subscribed. Changes are implemented according to a consensus process involving 90% of the members under the Agreement. Exh. IE-1 at 7. Now, rather than achieving the 90% consensus required to implement changes to that Agreement, the refund claimants are seeking ad hoc exceptions, supported by very few of the subscribers. If the parties to the WSPP Agreement cannot rely on the terms establishing finality of pricing of bilateral agreements, if they cannot rely on the provisions that require mutual consent for pricing changes, if they cannot rely on the consensus decisional process to which they agreed, then plainly they cannot rely on the Agreement itself.

---

[309] *Sierra*, 350 U.S. at 355 (emphasis supplied); *see also Potomac Elec. Power Co.,* 210 F.3d. at 406 (*quoting Papago Tribal Util. Auth*, 723 F.2d at 953 (citations omitted)); *see also, Northeast Util.Svc. Co.,* 55 F.3d at 691 (FERC can modify the terms of a contract under *Mobile-Sierra* where third parties are threatened by possible "under discrimination" or the imposition of an "excessive burden." (citations omitted)).

[310] *See* Exh. NPG-67 at 8 (stating only that "refunds would simply create some measure of equity to parties that are disproportionately harmed.").

[311] *Northeast Util. Svc. Co.*, 66 FERC ¶ 61,332 at 62,084-85 & nn. 65, 66, *reh'g denied*, 68 FERC ¶ 61,041 (1994), *aff'd*, 55 F.3d 686 (1st Cir. 1995).

The whole purpose of the Agreement was to establish a functioning and comprehensive market. The Commission cannot sensibly revise one provision retroactively at the request of select parties without destroying the core of the WSPP Agreement. Most certainly this is not consistent with the public interest, as discussed more fully in the following sections.

Moreover, according to TFG, refunds would be inconsistent with the Commission's goals to establish stable power markets. The Commission's April 26 Order sets rules for the California mitigation plan that establishes that market players will be able to operate, knowing that the rules will not continually change, and that prices will not be reset after-the-fact.[312] Retroactive changes are insidious and damaging to investors' confidence in the markets. Retroactive changes in a bilateral market inevitably cause a loss of confidence in the stability and predictability of the market.

Testimony presented by each of Drs. Jones and Tabors and Mr. Van Vactor concludes that a loss of confidence in the market will cause costs to consumers to increase, as market participants demand additional risk premiums and additional security for their transactions. *See* Exh. PPL-1 at 4:1-19, 15:3-6; Exh. PWX-1 at 10:5-10, 11:10-113, 12:6-13:4, 13:14-17; Exh. ENR-1 at 3:21-4:2; *see also* Exh. IE-1 at 11. Further, as shown by BPA's Mr. Oliver, regulatory interference will have a chilling effect on trading and would drive marketers out of the region, decreasing the number of market participants, diminishing market liquidity and adversely affecting reliability. A retroactive refund process is likely to result in a significant reluctance by many participants in the market to conduct transactions when prices are high, *i.e.*, in times of scarcity. Exh. BPA-1 at 23; Exh. PPL-1 at 7. These are the times when liquidity and competition are most required. Because spot market transactions are those for immediate delivery, they are exactly the kind of transactions which the Commission should insulate from the kind of challenges advanced in this case.

Market liquidity, with a large number of buyers and sellers and a large and diverse supply of products, is a key component of a well-functioning competitive market. Loss of liquidity will lead to greater price volatility in the future, particularly if combined with anemic investment in new capacity during an extended period of uncertainty. Introducing refund liability into a competitive market thus will decrease the number of market participants and increase prices. Refund claimants made no attempt to rebut this clear testimony as to the harm of refunds, TFG avers.

---

312 April 26 Order, 95 FERC ¶ 61,115 at 61,352.

Further, TFG argues, if refunds are ordered and price caps are not market responsive, demand response will be discouraged and perhaps reversed. The PNW demand response has been exemplary in achieving economic efficiency in the market. Exh. PPL-1 at 5-15. Setting artificial caps or reimposing cost-of-service ratemaking is exactly the opposite of what good public policy demands. *Id.*; Exh. PWX-1 at 9-18.

The April 26 Order also sought to "encourage, and not discourage, the critically needed investment in infrastructure."[313] A retroactive refund requirement will send warning signals to new investors that investment in this region is not secure and is subject to regulatory manipulation. Market signals to the supply side of the business, established at artificially low levels, will have the predictable effect of discouraging needed supply. To the extent that investors lose confidence in the market, capacity additions will evaporate. Given the nearly universal agreement that the western markets as a whole need substantial new capacity additions in the next several years, a loss of confidence and exit of investors is the very worst result that could be envisioned.

Moreover, TFG argues, that ordering retroactive refunds on the basis of a generic complaint will throw the certainty of market-based rates nationwide into disarray. On a more practical level, the TFG notes that it would be particularly destabilizing for the Commission to order retroactive refunds based solely on a generic complaint similar to the Puget Complaint. In most parts of the country, sellers with market-based rates have no price cap. If the Commission establishes a precedent that anyone filing a generic market complaint could qualify for refunds imposed retroactively, the entire wholesale electricity market could be chilled until any complaint, however spurious, is finally dismissed or resolved. Those who oppose competition – or who simply have negotiated uneconomic transactions for themselves – could unravel the competitive process by misuse of the complaint power. The reason for the notice requirements under Section 206 and the corresponding limitations on retroactive application are valid and should not, and legally cannot, be lightly disregarded. Thus, the Commission should be very careful in applying price mitigation retroactively and should tailor any refund liability as narrowly as possible. It should not extend its refund proceeding from California to the very different, and well-functioning, PNW marketplace.

Additionally, TFG asserts that granting refunds to the limited group of complainants would be inequitable. Requiring refunds will simply not produce equity. To the contrary, the record shows that refund claimants could have taken many actions to cover short positions with lower cost supply. They had options to build or to buy in the

---

[313] 95 FERC at 61,352.

forward markets but voluntarily chose to over rely on the spot market, which they knew or should have known was highly volatile. There is simply no rational basis to allow refunds to compensate those market participants who made clearly voluntary and unrestricted choices while penalizing the vast majority of suppliers in the PNW who used the forward markets to achieve a balanced portfolio and lower costs. This, again, would produce a result precisely the opposite of the Commission's stated goals and would reward the very behavior it found objectionable in the California market.

Nor would refunds provide even short term benefits to the few market participants seeking them, TFG avers. The evidence made clear that "Nothing is more likely to drive potential sellers away from a buyer than a re-trade. This business relies on finality of deals and reliance on your trading partner." Exh. IE-1 at 10. Balancing the short-term benefit of refunds to a few market participants against the immediate and long-term damage to the market and to future investment decisions, it is impossible to reconcile refunds with the overall public interest standard. It would be arbitrary and capricious and a reversal of all of its stated tenets for the Commission to attempt to justify refunds in the circumstances surrounding the PNW.

TFG additionally argues that refunds for transactions in the bilateral market are impossible as a matter of fact. Ripple claims have been excluded from this preliminary proceeding, however, they are a major impediment to a rational refund order.[314] Putting aside all other considerations, it would be simply impossible to identify and quantify the amount of refunds potentially owed by all parties in the PNW under virtually any plan. The scope and magnitude of ripple claims, the time that would be required for such claims to be determined, and the inability to identify or recover claims from certain parties precludes ordering refunds for bilateral transactions in the PNW.[315]

Complicating matters further, any particular spot transaction may have originated from a portfolio including a mix of short-term and long-term transactions. Exh. PWX-1 at 16. As Dr. Tabors explains, depending on the level of mitigation imposed, "the ripple could (and likely would) eventually touch every transaction that took place in the WSCC for the period of December 25, 2000 through June 20, 2001." Exh. PWX-1 at 16

---

[314] Order on Ripple Refund Claims, Docket No. EL01-10-000 (August 23, 2001) (Presiding Judge acknowledged that "It is apparent that there was a chain of buyers and sellers in connection with many, if not most of the spot market bilateral transactions that are the subject of this proceeding."); *see also* Exh. PWX-1 at 13-17; Exh. BPA at 21-22.

[315] *See generally* Order on Ripple Refund Claims.

(emphasis added). The sheer magnitude of this potential ripple liability is enough to cause the Commission to reject the possibility of refunds in this proceeding.

The immense number of potential ripple claims is directly related to the highly active nature of the PNW wholesale electricity market. As Dr. Tabors explains, electricity in the PNW region is traded an average of six times between the point of generation to the last wholesale purchaser in the chain. Exh. PWX-9 at 7. Powerex alone estimates that it engaged in approximately 30,000 transactions during the period from December 25, 2000 through June 20, 2001 PWX-9 at 6. Dr. Tabors conservatively estimates, and the NPG does not challenge, that approximately 500,000 transactions would have to be recalculated based on a refund order in the PNW. Exh. PWX-1 at 17. Given the sheer magnitude of contracts that would have to be rewritten as a result of imposing refunds, it would be impossible to unwind fairly the chain of transactions that resulted in a single bilateral sale between December 25, 2000 and June 20, 2001.

Putting the magnitude of potential ripple claims aside, as a factual matter it may be impossible for purchasers to recover ripple liability given the large number of sellers in the PNW that are not subject to the Commission's jurisdiction and the inability to trace upstream sellers in every transaction. Exh. BPA-1 at 22. Most, if not all, buyers and sellers purchase and sell from a portfolio of resources. Whereas in some instances a "back-to-back" purchase and sale (identical in volume, price, terms and conditions) is made and respective buyers and sellers can be identified, in many instances a particular seller's resource portfolio is an aggregate of a wide variety of supply rights which may include ownership or contractual rights to generation output, long and short-term contracts with other marketers, options, and even rights to call for demand reductions negotiated at a price with load users. Further, if some type of arbitrary hourly price were used as a refund benchmark, parties would have to be permitted to offset sales at this retroactive price cap with sales below this cap. Exh. BPA-1 at 19. In these situations, it would be nearly impossible to match a particular sale with its source or to calculate the alleged refund due with precision. As a result, Mr. Oliver testified that even if all potential ripple claims could be identified, only a fraction of the transactions actually would be adjusted, leaving certain parties to shoulder the brunt of refunds. *Id.* at 21-22. It would take a protracted evidentiary proceeding to begin unraveling the multiple waves of ripple claims. *Id.*; Exh. BPA-1 at 22; Exh. PWX-1 at 15-17.[316]

TFG maintains that extending this proceeding to examine ripple claims would thus introduce a considerable level of regulatory risk and unfairness into every subsequent

---

316 *See id.*

transaction, thereby disrupting PNW markets to an unacceptable extent. Exh. BPA-1 at 23; *see also* Exh. PPL-1 at 7; Exh. PWX-1 at 18. This uncertainty and risk will require sellers in all transactions to raise prices, representing a risk premium, and may even cause sellers to abandon the market entirely. Exh. PWX-1 at 17-18; Exh. BPA-1 at 23; Exh. PPL-1 at 7. As has already begun to happen in California, investment in additional generation will be discouraged as potential investors question whether the market will be sufficiently stable to provide for a return on their investment. Exh. CHPUD-1 at 6.

Finality of transactions, according to TFG, is a fundamental requirement of a vibrant, sustainable electricity market. Requiring parties to unwind past transactions and rewrite complete contracts "remove[s] all faith in the wholesale electric market." Exh. PWX-1 at 17. Unleashing the ripple claims would thus spiral the PNW market down a rabbit-hole from which it will not recover for many years. For this reason alone, the Presiding Judge should recommend to the Commission that refunds not be ordered in this proceeding, and that this entire matter be terminated with prejudice.

"Book-Out" transactions are outside the scope of this proceeding, TFG contends. Refund claimants also have attempted to include financial "book-out" transactions in this proceeding, contradicting clear precedent that such transactions are not even subject to the Commission's jurisdiction. *See*, *e.g.*, Exh. NPG-67 at 10-11. As the spot market includes only transactions for immediate delivery, by definition the spot market cannot include financial "book-out" transactions.[317] Since book-outs do not result in the physical delivery of electricity at any time, much less in the immediate spot market, such transactions cannot fall within the definition of spot market or the scope of this proceeding. The inclusion of book-out transactions also cannot be reconciled with clear precedent that book-out transactions are not subject to the Federal Power Act in the first instance.[318] Book-outs do not, and, therefore, are not subject to Commission

---

[317] Book-out transactions are transactions that, for a variety of reasons (such as the presence of transmission constraints or offsetting purchase and sale transactions), do not result in physical delivery of electricity. These transactions are instead settled financially.

[318] Commission precedent on this issue is clear – the Commission has asserted jurisdiction only over those transactions that result in the physical delivery of electricity. The Commission has jurisdiction under Sections 205 and 206 of the Federal Power Act only where three conditions are present: where "[(i)] the electricity futures contract goes to delivery, [(ii)] the electric energy sold under the contract will be resold in interstate

(continued...)

jurisdiction.[319] Accordingly, no claim of refunds for book-out transactions is properly before the Commission.

BONNEVILLE/BPA:

BPA's Vice President for Bulk Power Marketing, Stephen R. Oliver, testified, that as a practical matter only a limited number of the transactions at issue in this proceeding could ever be adjusted if the Commission were to attempt to order refunds. BPA-1, at 21. In addition, BPA is very concerned that the precedent set by an order by the Commission for refunds in the Pacific Northwest for the relevant time period could result in reliability problems in the region if sellers, as a consequence, hesitate to conduct transactions when prices begin to rise. *Id*. at 23. However, if the Commission does order refunds, the refund calculation must credit sellers for transactions below the mitigated market-clearing price, whatever that might be. BPA-1 at 19.

Even if the Commission were to adopt a relatively narrow definition of spot market bilateral sale, BPA believes it would be impossible to identify and calculate the amount of refunds that would be owed by all sellers in the Pacific Northwest. Because there is not a centralized spot market used for serving native load requirements in the Pacific Northwest, as there is in California, unwinding these transactions will be virtually

---

(...continued)
commerce, [(iii)] and the seller is a public utility." *New York Mercantile Exchange*, 74 FERC ¶ 61,311 at 61,987 (1996) ("*NYMEX*"). *See also* Exh. PSCO-1 at 7:9-16 (*citing Morgan Stanley Capital Group,* 69 FERC ¶ 61,175 at 61,696 (1994), *clarified, Englehard Power Marketing, Inc.*, 70 FERC ¶ 61,250 at 61,778, *order on reh'g,* 72 FERC ¶ 61,082 at 61,436-37 (1996)).

[319] This position is fully consistent with the Commission's electricity sales reporting requirements. All electric utilities, including power marketers, must report each year to the Commission their jurisdictional electric power transactions on the Commission's Form No. 582. The Commission has addressed the question of book-out transactions with regard to its Form 582 reporting requirements. *Annual Charges Under the Omnibus Budget Reconciliation Act (CNG Power Services, et al.),* 87 FERC ¶ 61,074 (1999) ("*CNG Services*"). In *CNG Services*, the Commission clarified that book-out transactions need not be reported in Form 582, stating "the parties need to report on their Form Nos. 582 only those transactions that result in the *delivery* of electric energy." *Id.* at 61,303 (emphasis added).

impossible. BPA-1, at 22. As Judge Cintron correctly noted in the Order on Ripple Claims, dated August 23, 2001:

> [f]rom the factual record already compiled and the representations of the parties to me, it is apparent that there was a chain of buyers and sellers in connection with many, if not most of the spot market bilateral transactions that are the subject of this proceeding. Accordingly, the number of refund claims that could develop in each successive ripple could become very large.

Order at 2 (mimeo).

Indeed, BPA testified that many of these transactions are multi-layered, complicating the ability to successfully identify and effectively unwind the transactions. BPA-1, at 22. For example, BPA made numerous remarketing sales of power that became available due to reduction in the operations of a number of its direct service industrial (DSI) customers during the relevant period, at prices negotiated by the DSI customer. BPA was obligated under contracts it entered into with many of these DSIs in 1995 to either credit the power bills of such DSIs by the amount of the revenues from such remarketing sales, or make cash payments to the DSI if the credit would exceed the amount owed by the DSI to BPA under its wholesale power bill. BPA-1, at 11. The sales of remarketed power made by BPA to Seattle City Light and the remarketing sale to Clark PUD are examples of such transactions. BPA-1, at 10-12; BPA-2 at 4-6. The remarketing transactions with Seattle are the subject of a refund claim against BPA, notwithstanding the fact that revenues associated with those sales were ultimately paid by BPA to a DSI customer. BPA-1, at 10. If revenues credited or paid by BPA to DSI customers are subject to refund, either with respect to the claims made in this proceeding or as part of any ripple claims, it is not clear that any DSI customer will have the financial ability to refund monies already earmarked and committed for employee compensation or power resource development. *Id*. at 21.

In addition, entities that purchased remarketed power may be tagged with refund obligations as downstream sellers of that power. *Id.* at 22. Certainly, notwithstanding the fact that BPA made the power sales on the DSI customers account, BPA should not and cannot be made to refund the revenues associated with those sales paid to the DSI customers. Seattle's claim against BPA in this proceeding seeks exactly that result.

In addition, many participants in the market took steps, including BPA, to mitigate or avoid the high costs of transactions during the relevant period. *Id*. These efforts included expenditures for long-term forward purchases at prices influenced by the spot market, undertaking conservation measures, and curtailment efforts all of which are outside the scope of this proceeding. Given the vast nature of the problem and the limitations of the solution being undertaken here, the Commission should not attempt to order refunds in this proceeding because to do so would only provide partial equity which will undoubtedly compound the problems of the past winter for many market participants

Perhaps most importantly, because so many sellers in the Pacific Northwest are non-jurisdictional entities, and therefore not subject to a Commission refund order, even if all the transactions implicated in any refund order could be identified and calculated, many of them ultimately will not be part of the refund equation. As a consequence, only some parties will shoulder the brunt of any refunds. BPA-1, Oliver at 22.

In addition, BPA contends that ordering refunds in the Pacific Northwest could result in regional reliability problems. BPA-1, at 23. The potential for refunds in the future is likely to result in a significant reluctance by many participants in the market to conduct transactions when prices are high. *Id.* The Prepared Answering testimony of Mr. Philip Movish challenges BPA's observation that reliability may suffer if the Commission orders refunds. NPG-60, at 13. Mr. Movish suggests that with the Commission's mitigation measures in place, there should be no need for future refunds. *Id*.

However, BPA's position on this issue is not a conclusion of economic theory based on the ineffectiveness of the Commission's mitigation measures, but rather a practical business observation by BPA's witness based on actual hands-on experience operating in the Pacific Northwest electric power markets, including the spot markets. Mr. Movish concedes that he lacks such experience, and in preparing his testimony did not consult with any traders that are actively trading in the Pacific Northwest. Hearing Tr. at 740:8-17. In fact, hesitancy to conduct business in the electricity market without a great deal of certainty about the sustain ability of the transaction will be particularly dangerous during emergency situations when supply is tight and prices tend to be higher. BPA-1, at 23. Because electricity transactions often occur during real-time, almost on an instantaneous basis, if parties hesitate to conduct transactions then reliability issues may arise. *Id*. Testimony filed on behalf of the Transaction Finality Group similarly concludes that introducing refund liability into the Pacific Northwest electric power markets will decrease the number of market participants and increase prices. PPL-1, Jones at 4:1-19; at 15:3-6. PWX-1, Tabors at 10:5-10; at 11:10-113; at 12:6-13:4; at 13:14-17. ENR-1, Van Vactor at 3:21-4:2. BPA agrees with the conclusion drawn in this testimony that a loss of confidence in the market will cause costs to consumers to increase, as market participants either exit the market, or demand additional risk premiums and additional security for their transactions.

However, if the Commission elects to order refunds in the Pacific Northwest, sellers should be credited for transactions that are both above and below the mitigated market-clearing price. Logic dictates that if purchasers claim refunds for charges above the mitigated market clearing price, they should also pay the difference between the mitigated clearing price and the price paid. BPA-1 at 19. Part of the underlying theory behind these refund claims is an attempt to replicate a transparent market. Under this theory, in a transparent market there would be a price at which all sales would be made during a specific period of time. Sellers and buyers should get the benefits of any attempt to replicate the market-clearing price. Therefore any methodology in the Pacific Northwest should include both upward and downward adjustment to the mitigated market-clearing price. *Id*.

RECOMMENDATIONS

The Commission dismissed Puget's complaint in the December 15 order. Puget filed a petition for rehearing of this decision. The Commission has not acted on this rehearing request. On July 24, 2001, Puget filed to withdraw its complaint and rehearing request. In the July 25 decision the Commission stated it would consider Puget's withdrawal request after this hearing. Based on the evidence developed in this case I recommend that the Commission affirm its decision to dismiss the complaint and grant the motion to withdraw. Puget is no longer prosecuting its Complaint for any purpose. Tr. at 727. I agree with TFG that intervenors cannot pursue their refunds requests based on a dismissed complaint and a complaint which Puget has sought to abandon. Moreover, as discussed in issue number one, above, Puget's complaint sought prospective remedy only. The request for refunds under these circumstances violates the Commission's longstanding policy prohibiting intervenors from expanding complaints initiated by others. *See e.g. Louisiana Power & Light Company*,[320] (the Commission held that it would not treat pleadings (motions, interventions))filed by third parties in a complaint proceeding initiated by another party as the complaint itself.) Allowing intervenors to prosecute a refund claim beyond the scope of the Complaint initiated by Puget and beyond the procedural path of that Complaint, including its withdrawal, will therefore improperly expand the function of intervenor to that of a complainant. Therefore, the December 25, 2000 cannot be the refund effective date. If the Commission reverses its dismissal, Puget's motion to withdraw will need to be addressed. If further proceedings are ordered in this case, the applicability of the Sierra Mobile doctrine to the specific claims against bilateral transactions entered under the WSPP Agreement would have to be determined. In this proceeding, refund claimants have not established any of the

[320] 50 FERC ¶ 61,040 at 61,062 (1990) ("*Louisiana Power*").

exceptions of the Sierra Mobile doctrine, in order to be entitled to modification of contractual terms under the public interest standard.

Evidence of record indicates that refunds would have a negative impact to the Pacific Northwest market. Testimony presented by each of Drs. Jones and Tabors and Mr. Van Vactor concludes that a loss of confidence in the market will cause costs to consumers to increase, as market participants demand additional risk premiums and additional security for their transactions. *See* Exh. PPL-1 at 4:1-19, 15:3-6; Exh. PWX-1 at 10:5-10, 11:10-113, 12:6-13:4, 13:14-17; Exh. ENR-1 at 3:21-4:2; *see also* Exh. IE-1 at 11. Further, as shown by BPA's Mr. Oliver, regulatory interference will have a chilling effect on trading and would drive marketers out of the region, decreasing the number of market participants, diminishing market liquidity and adversely affecting reliability. A retroactive refund process is likely to result in a significant reluctance by many participants in the market to conduct transactions when prices are high, *i.e.*, in times of scarcity. Exh. BPA-1 at 23; Exh. PPL-1 at 7. These are the times when liquidity and competition are most required. Because spot market transactions are those for immediate delivery, they are exactly the kind of transactions which the Commission should insulate from the kind of challenges advanced in this case. Furthermore, the April 26 Order also sought to "encourage, and not discourage, the critically needed investment in infrastructure." A retroactive refund requirement will send warning signals to new investors that investment in this region is not secure and is subject to regulatory manipulation. Market signals to the supply side of the business, established at artificially low levels, will have the predictable effect of discouraging needed supply. To the extent that investors lose confidence in the market, capacity additions will evaporate. Given the nearly universal agreement that the western markets as a whole need substantial new capacity additions in the next several years, a loss of confidence and exit of investors is the very worst result that could be envisioned. I am not persuaded by the arguments advanced by the California Parties attempting to contradict this testimony.

I agree with TFG that refunds would not provide even short term benefits to the few market participants seeking them. The evidence indicates that "Nothing is more likely to drive potential sellers away from a buyer than a re-trade. This business relies on finality of deals and reliance on your trading partner." Exh. IE-1 at 10. Balancing the short-term benefit of refunds to a few market participants against the immediate and long-term damage to the market and to future investment decisions, it is impossible to reconcile refunds with the overall public interest standard.

BPA agrees with TFG in this regard. Exh. BPA- 1 at 23. Mr. Philip Movish challenges BPA's observation that reliability may suffer if the Commission orders refunds. NPG-60, at 13. Mr. Movish suggests that with the Commission's mitigation measures in place, there should be no need for future refunds. *Id*. However, BPA's claims that its position on this issue is not a conclusion of economic theory based on the ineffectiveness of the Commission's mitigation measures, but rather a practical business observation by BPA's witness based on actual hands-on experience operating in the Pacific Northwest electric power markets, including the spot markets. Mr. Movish concedes that he lacks such experience, and in preparing his testimony did not consult with any traders that are actively trading in the Pacific Northwest. Hearing Tr. at 740:8-17. In fact, hesitancy to conduct business in the electricity market without a great deal of certainty about the sustain ability of the transaction will be particularly dangerous during emergency situations when supply is tight and prices tend to be higher. BPA-1, at 23. Because electricity transactions often occur during real-time, almost on an instantaneous basis, if parties hesitate to conduct transactions then reliability issues may arise.

The evidence in this case also shows that determining the number of transactions subject to refunds would be a very complex task. The immense number of potential ripple claims is directly related to the highly active nature of the PNW wholesale electricity market. As Dr. Tabors explains, electricity in the PNW region is traded an average of six times between the point of generation to the last wholesale purchaser in the chain. Exh. PWX-9 at 7. Powerex alone estimates that it engaged in approximately 30,000 transactions during the period from December 25, 2000 through June 20, 2001 PWX-9 at 6. Dr. Tabors conservatively estimates, and the NPG does not challenge, that approximately 500,000 transactions would have to be recalculated based on a refund order in the PNW. Exh. PWX-1 at 17. Given the sheer magnitude of contracts that would have to be rewritten as a result of imposing refunds, it would be impossible to unwind fairly the chain of transactions that resulted in a single bilateral sale between December 25, 2000 and June 20, 2001.

Moreover, the evidence shows that as a factual matter it may be impossible for purchasers to recover ripple liability given the large number of sellers in the PNW that are not subject to the Commission's jurisdiction and the inability to trace upstream sellers in every transaction. Exh. BPA-1 at 22. Most, if not all, buyers and sellers purchase and sell from a portfolio of resources. Whereas in some instances a "back-to-back" purchase and sale (identical in volume, price, terms and conditions) is made and respective buyers and sellers can be identified, in many instances a particular seller's resource portfolio is an aggregate of a wide variety of supply rights which may include ownership or contractual rights to generation output, long and short-term contracts with other marketers, options, and even rights to call for demand reductions negotiated at a price with load users. Further, if some type of arbitrary hourly price were used as a refund benchmark, parties would have to be permitted to offset sales at this retroactive price cap with sales below this cap. Exh. BPA-1 at 19. In these situations, it would be nearly impossible to match a particular sale with its source or to calculate the alleged refund due with precision. As a result, Mr. Oliver testified that even if all potential ripple claims could be identified, only a fraction of the transactions actually would be adjusted, leaving certain parties to shoulder the brunt of refunds. *Id.* at 21-22. It would take a protracted evidentiary proceeding to begin unraveling the multiple waves of ripple claims. *Id.*; Exh. BPA-1 at 22; Exh. PWX-1 at 15-17.[321]

For instance, BPA made numerous remarketing sales of power that became available due to reduction in the operations of a number of its direct service industrial (DSI) customers during the relevant period, at prices negotiated by the DSI customer. BPA was obligated under contracts it entered into with many of these DSIs in 1995 to either credit the power bills of such DSIs by the amount of the revenues from such remarketing sales, or make cash payments to the DSI if the credit would exceed the amount owed by the DSI to BPA under its wholesale power bill. BPA-1, at 11. The sales of remarketed power made by BPA to Seattle City Light and the remarketing sale to Clark PUD are examples of such transactions. BPA-1, at 10-12; BPA-2 at 4-6. The remarketing transactions with Seattle are the subject of a refund claim against BPA, notwithstanding the fact that revenues associated with those sales were ultimately paid by BPA to a DSI customer. BPA-1, at 10. If revenues credited or paid by BPA to DSI customers are subject to refund, either with respect to the claims made in this proceeding or as part of any ripple claims, it is not clear that any DSI customer will have the financial ability to refund monies already earmarked and committed for employee compensation or power resource development. *Id*. at 21.

I recommend that book out transactions not be part of this proceeding. I agree with TFG that "book out" transactions are not part of this proceeding.

SUMMARY

Prices in the PNW during the period 12/25/00 - 6/20/01 were the result of a number of factors, the shortage of supply, excess demand, drought, increased price in natural gas along with the price signals from the California markets. The PNW is a competitive market and has been for a long time. The transactions involved in this proceeding resulted from bilateral agreements between the parties. Under these circumstances the prices were not unreasonable or unjust and refunds should not be ordered in this proceeding. I recommend the proceeding be terminated by affirming the

---

[321] *See id.*

December 15 dismissal of Puget complaint and allowing Puget to withdraw its rehearing request.

PROPOSED FINDINGS OF FACT

1) The PNW is defined by the Pacific Northwest Electric Power Planning and Conservation Act.

2) Southbound wholesales of power at the California–Oregon border ("COB") and the Nevada-Oregon Border ("NOB") are not within the PNWfor purposes of this case, because the delivery point is not to a PNW load server and deliveries actually take place in California.

3) The PNW is uniquely dependent upon hydroelectric power since approximately 80 percent of the region's generation capacity by fuel type is hydroelectric.

4) Although the California and PNW markets are closely interrelated, they are characterized by important and fundamental differences:

> California handles spot market transactions through a centralized clearinghouse while PNW uses bilateral contracts to consummate spot market sales.
>
> California relies primarily upon fossil fueled generation, while the Pacific Northwest relies predominantly upon hydropower.

5) For purposes of this proceeding, spot market transactions in the PNW comprise all sales for 24 hours or less that are entered into one day in advance or, before weekends, holidays, or WSCC scheduler conferences, up to 48 hours in advance, and within the month and balance of the month transactions executed during the period December 25, 2000 through June 20, 2001 with PNW delivery points to serve loads within the PNW.

6) The PNW market is dominated by forward contractual hedging and little spot market activity.

7) Bilateral spot market sales of electricity in the PNW are negotiated at arms-length between willing buyers and sellers and ordinarily reflect circumstances unique and specific to the seller and buyer.

8) During the relevant period, spot market sales in the PNW were made pursuant to bilateral agreements entered into by the parties to the transactions, typically pursuant to the terms of the Western Systems Power Pool Agreement.

9) The WSPP Agreement is a default standardized contract for electric power sales and physical options.

10) The WSPP comprises more than 220 members.

11) The WSPP Agreement applies to transactions between WSPP members.

12) Three basic products sales are covered by the WSPP Agreement: Economy Energy Service (Service Schedule A), Unit Commitment Service (Service Schedule B) and Firm Sales/Exchange Service (Service Schedule C).

13) Utilities that purchase electricity to serve load in the PNW can assemble a portfolio of long, medium, and short-term contracts in order to minimize their exposure to volatile spot market prices.

14) During the relevant period, the PNW power market, including the market for bilateral spot transactions, performed as a competitive market.

15) Supppliers of electricity into the PNW are numerous.

16) There are a very large number of actual and potential competitors in the power sales market in the PNW.

17) In 2000 and 2001, power supply shortages relative to demand affected prices in the west.

18)Temperatures in the early winter of 2000-01 in the PNW were colder than normal.

19) In November and December 2000 precipitation in the PNW remained at record low levels.

20) During the 2000-2001 period, the PNW experienced its worst drought in 50 years.

21) Price increases in the PNW during the relevant period, reflect shortages in water supplies, weather, and natural gas prices. The traditional trading patterns between California and its northern neighbors - electricity shipped from the PNW to California in

the summer and returned by California to the PNW in the winter - failed in the winter of 2000-01 because California had no surplus electricity to offer to northwest utilities in that winter.

22) In September 2000, Powerex offered to sell electricity under forward contracts for the first quarter of 2001 at $75.50 and $81 per megawatt hour.

23) For several years preceding the relevant period, wholesale electricity prices in the PNW were relatively quite low.

24) Hedges for spot price volatility existed during the relevant period in the Pacific Northwest in the form of bilateral forward, futures, over-the-counter forward contracts, and self-build options also existed before and during the relevant period.

25) CDWR’s purchases during the potential refund period were at market-based rates under the WSPP Agreement.

26) CDWR makes purchases solely for California loads. It does not make purchases for consumers outside of California.

27) CDWR does not maintain offices or conduct operations in the PNW. CDWR does not contract for transmission in the PNW.

28) CDWR’s purchases were made at four interconnect points on the boundary of the PNW and California: COB, the NOB, Summit and Cascade. In the case of the COB and NOB interconnect points, CDWR took delivery at substations located within California.

29) All but a *de minimis* number of CDWR’s bilateral transactions during the potential refund period involved purchases from the PNW, and not sales into the PNW.

30) CDWR’s transactions for which the California Parties claim refunds are not within the scope of Puget Sound Energy’s October 26, 2000 Complaint in Docket No, EL01-10.

31) CDWR is not an intervenor in this proceeding.

32) Refund claims with respect to CDWR's bilateral purchases are being asserted by the "California Parties" (the Attorney General of the State of California, the California Electricity Oversight Board and the California Public Utilities Commission).

33) The California Parties claim $1,465,632,884 in refunds with respect to bilateral purchases by CDWR, and the payback in kind of 361,165 MWh in energy delivered by CDWR to PNW counterparties under exchange arrangements ($46,612,654) (a total of $1,512,213,967 including the exchange transactions).

34) CDWR is not seeking refunds in this proceeding.

35) The California Parties have failed to show why all of CDWR's bilateral transactions are not subject to the July 25 Order wherein the refund claims for bilateral contracts by CDWR were rejected by the Commission, in Docket Nos. EL00-95 *et al.*

36)There is no basis for considering the California Parties' refund claims in Docket No. EL01-10. There is no need for further proceedings with respect to these claims in connection with this PNW proceeding, and these claims should be dismissed from Docket No. EL01-10, as being beyond the scope of this proceeding.

37)Any "sleeved" transaction, exchanges or aggregation arrangements and "booked-out" transactions are outside the scope of this proceeding.

38)The preponderance of the evidence establishes the lack of exercise of market power by any seller in the PNW.

39)Only seven PNW purchasers out of a universe of 220 members of the Western Systems Power Pool ("WSPP") are asking the Commission to award them refunds: City of Seattle $278,000,000; City of Tacoma $65,407,755; Port of Seattle $9,371,660; Northern Wasco People's Utility District $44,089,364; Eugene Water and Electric Board $39,719,000; Sacramento Municipality Utility District $4,587,511 and Clark Public Utilities $64,080,603.

40)The total volume of spot market bilateral sales in the PNW for the period December 25, 2001 through June 20, 2001 is likely higher than the volumes shown on the confidential data submissions of August 16, 2001 (certified to the Commission as part of the record in this proceeding) since data was not received from all sellers.

41)There is no indication from approximately 75 percent of WSPP members of whether or not they participated in the PNW spot market during the relevant time period.

42)Most of the sales transactions reported in the data submissions were made pursuant to the standard WSPP agreement.

43)The rights of all parties to assert an entitlement to refunds for bilateral spot market purchases in the PNW in the event that such party is ordered to pay refunds have been preserved.

44)Prices for approximately 500,000 bilateral spot market transactions will have to be reset if all purchasers eligible for refunds assert their right to receive refunds. These are the so-called “ripple” claims.

45)As a factual matter, it may be impossible for purchasers to recover their ripple refund claims because of the difficulty in tracing upstream sellers in every transaction.

46)The jurisdictional reasoning that underlies the assertion of refund authority over power sales of non-public utilities to the California ISO and Power Exchange markets in the July 25 order, in Docket EL00-95, does not apply to bilateral power sales of non-public utilities in the Pacific Northwest.

47) Puget Sound's complaint was dismissed by order dated December 15, 2000. No other section 206 complaint has been filed by any party to this proceeding. Thus, no refund effective date has been established for ordering refunds in this proceeding.

48) The parties have failed to show that market-based prices charged in the PNW during the potential refund period were unjust and unreasonable.

CARMEN A. CINTRON

Presiding Adminstrative Law Judge